NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2023 State of Reliability Technical Assessment

June 2023

Technical Assessment of 2022 Bulk Power System Performance

2023 SOR Overview | 2023 SOR Video | 2023 SOR Infographic

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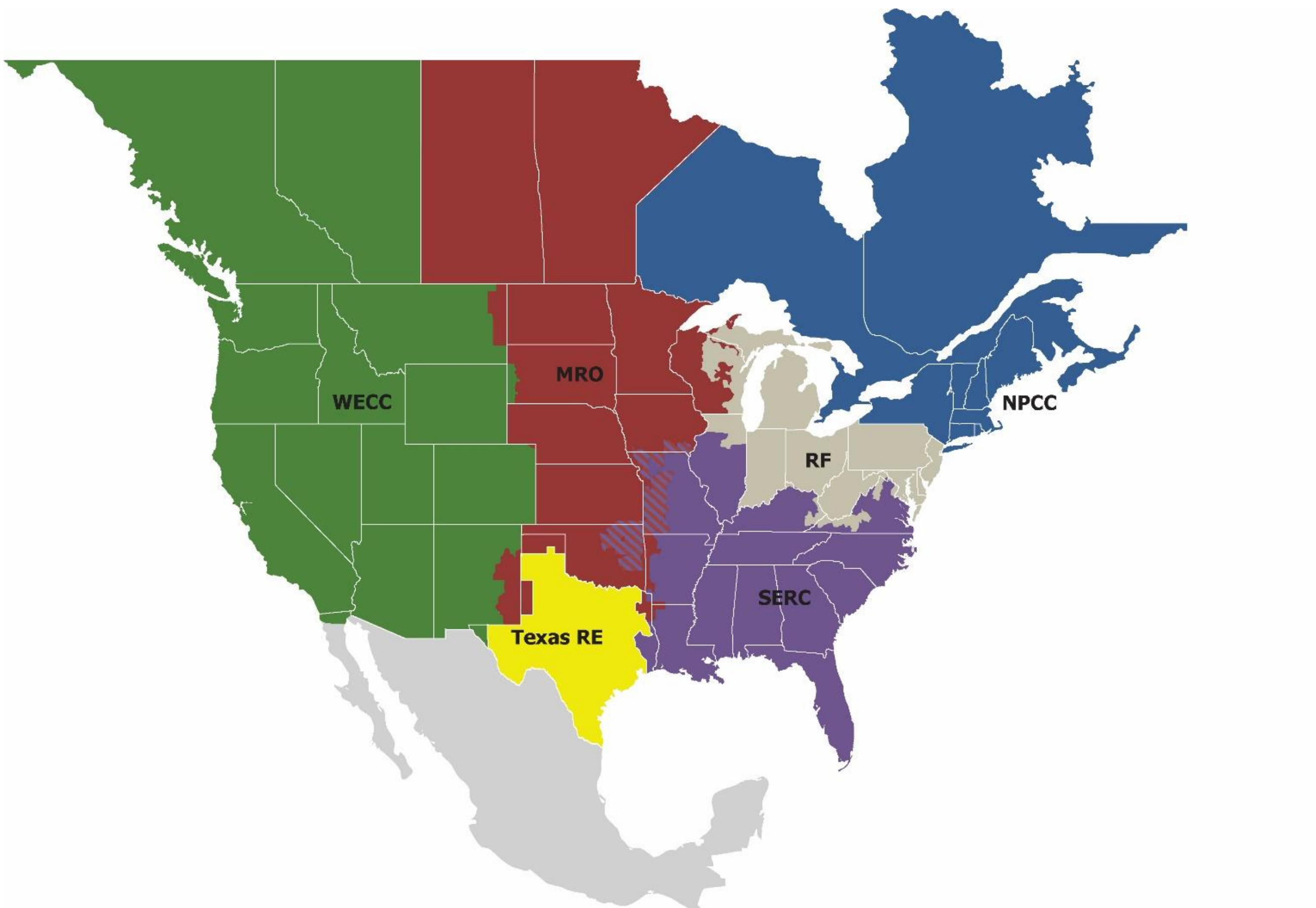
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Transmission Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Technical Assessment

Introduction

This year's State of Reliability (SOR) is comprised of two publications: the *2023 State of Reliability Overview,*[1] which is a high-level summary of the important findings, and this *2023 State of Reliability Technical Assessment,* which provides NERC's detailed comprehensive and annual technical review of BPS reliability for the 2022 operating (calendar) year.

The *2023 State of Reliability Overview* replaces the executive summary normally found in NERC reports. This *2023 State of Reliability Technical Assessment* provides detailed descriptions of key findings and key occurrences for 2022 along with in-depth analysis of risks and resilience, grid transformation, grid performance, and the status of performance metrics.

Purpose of the SOR

Both the overview and the technical assessment provide objective and concise information for policymakers, industry leaders, and regulators on issues that affect the reliability and resilience of the North American BPS. Specifically, the SOR does the following:

- Identifies system performance trends and emerging reliability risks
- Reports on the relative health of the interconnected system
- Measures the success of mitigation activities deployed

NERC, as the ERO, works to assure the effective and efficient reduction of reliability risks as well as the security risks of the North American BPS. Annual and seasonal risk assessments look to the future, and special reports on emergent risks serve to identify and mitigate potential risks. The annual SOR provides analyses of past BPS performance. This assessment documents BPS adequacy and identifies performance trends in addition to providing strong technical support for those interested in the underlying data and detailed analytics.

NERC defines the reliability[2] of the interconnected BPS in terms of the following three basic and functional aspects:

- Adequacy
- Operating Reliability
- Adequate Level of Reliability

The *2023 State of Reliability* focuses on BPS[3] performance during the prior calendar year as measured by an established set of reliability indicators and more detailed analysis performed by ERO staff and technical committee participants. Data used in the analysis comes from the Transmission Availability Data System (TADS), the Generating Availability Data System (GADS), the Misoperation Information Data Analysis System (MIDAS), the Long-Term Reliability Assessment (LTRA), voluntary reporting into The Event Analysis Management System (TEAMS), the Electricity Information Sharing and Analysis Center (E-ISAC), and the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group. ERO staff developed this independent assessment with support from the Performance Analysis Subcommittee.

[1] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2023_Overview.pdf

[2] **Learn About NERC** provides background information about NERC, the definition of reliability, and the electric grid.

[3] The term BPS is defined in Section 215 of the Federal Power Act to encompass the facilities, control systems, and electric energy needed to operate an interconnected electric energy transmission network and maintain transmission system reliability, excluding facilities used to locally distribute electricity. BES is a FERC-approved term defined in NERC's *Glossary of Terms*. The BES is, in short, the portion of the BPS to which NERC's standards apply and from which data are collected for analysis.

Considerations

- Data in the SOR represents the performance for the January–December 2022 operating year unless otherwise noted.
- Analysis is based on data from 2018–2022 that was available Spring 2023 and provides a basis to evaluate 2022 performance relative to performance over the last five years. All dates and times shown are in Coordinated Universal Time (UTC).
- The SOR is a review of industry-wide trends and not a review of the performance of individual entities.
- When analysis is presented by Interconnection, the Québec Interconnection is combined with the Eastern Interconnection unless specific analysis for the Québec Interconnection is shown.

Key Findings and Resultant Actions

Based on data and information collected for this assessment of BES reliability performance in 2022, NERC identified four key findings and is taking actions to address them. Although extreme weather continues to present the biggest overlying reliability challenge to the BES, only topics related to the BES have been listed as key findings.

Key Finding 1

Conventional Generation Reliability

The reliability of conventional generation is significantly challenged by more frequent extreme weather, high-demand conditions, and a changing resource mix, resulting in higher overall outage rates and surpassing transmission in their contribution to major load loss events.

While the reliability of conventional generation has remained stable during normal operating conditions, the increased intensity and frequency of extreme weather events has contributed to a gradual rise in the conventional generation forced outage rate in recent years. In 2022, conventional generation experienced its highest level of unavailability (8.5%) overall since NERC began gathering GADS data in 2013 as measured by the weighted equivalent forced outage rate (WEFOR). WEFOR is the percentage of megawatt (MW) hours a generator is unavailable. Further analysis indicates that there is a statistical correlation between the number of startups and forced outages on coal units.

Each year, the SOR identifies top stressed days from across North America based on the severity risk index (SRI). The SRI is a calculation of daily performance based on transmission, generation, and load loss components. In past years, the highest stress SRI days have been reflected in the coincidence of significant transmission losses and load loss events related to specific storms, hurricanes, or other newsworthy events.

Recently, the highest SRI days have shifted to days when generation unavailability and load loss occur simultaneously, such as during the February 2021 and December 2022 time periods. This suggests that generation capability during periods of extreme weather is now the greatest indicator of risk for the BES. This is an emerging risk, particularly when considered with consistently increasing coal outage rates throughout the year, the higher penetration of variable energy resources (VER) (such as wind and solar photovoltaic (PV)), and poor natural gas performance during extreme weather and high demand conditions. Analysis of a wider range of planning scenarios to determine increasingly common weather conditions that may affect large numbers of generation over a wide geographic footprint may be needed.

Resultant Actions

- NERC issued a Level 3 essential action alert[4] in May 2023: *Essential Actions to Industry - Cold Weather Preparations for Extreme Weather Events*.[5]
- Three standards were revised as a result of the 2019 cold weather event that became effective April 1, 2022;[6] additional standards revisions resulting from the 2021 cold weather event are ongoing.[7]
- NERC published three lessons learned[8] documents.

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4 https://www.nerc.com/pa/rrm/bpsa/Pages/About-Alerts.aspx

5 https://www.nerc.com/news/Pages/NERC-Releases-Essential-Action-Alert-Focused-on-Cold-Weather-Preparations.aspx

6 https://www.nerc.com/pa/Stand/Pages/Project%202019-06%20Cold%20Weather.aspx

7 https://www.nerc.com/pa/Stand/Pages/Project-2021-07-ExtremeColdWeather.aspx

8 LL20220301 "Managing UFLS Obligations and Service to Critical Loads during an Energy Emergency
LL20221201 "Air Breaker Cold Weather Operations
LL20230401 "Combustion Turbine Anti-Icing Control Strategy

- *FERC - NERC - Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States.*[9]
- The Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity joint report on the 2022 Winter Storm Elliott is expected in late 2023.
- NERC hosted its annual Preparation for Severe Cold Weather webinar.
- Reliability assessment data requests were expanded to further measure preparedness during cold weather events.
- The WECC Reliability Risk Committee is identifying specific risk areas under "Extreme Natural Events" that pose unique risks to the Western Interconnection and how industry can best address them.
- NERC GADS Section 1600 data request revisions,[10] which include reporting of specific environmental contributing factors for outages and event performance for wind and solar PV plants, become effective January 1, 2024.

Key Finding 2

Solar PV Inverter Performance during Transmission Faults

To continue benefiting from the rapid expansion of inverter-based resources, their dynamic performance during system events must improve.

On June 4, 2022, more than 1,700 MW of solar PV resource power output was lost in the Texas Interconnection, titled the Odessa Disturbance event. This event is nearly identical to an event that occurred one year prior at the same location. When combined with the loss of synchronous generation, the event in 2022 nearly exceeded the Texas Interconnection's resource loss protection criteria (RLPC). Details on this event are provided in the Texas Loss of Solar PV section of **Chapter 1**.

Recent Western Interconnection events show that newly built solar PV and battery storage resources are still being commissioned with the same performance issues highlighted in multiple disturbance reports since 2016.

Resultant Actions

- FERC notice of Proposed Rulemaking issued November 17, 2022, was released to address concerns regarding reliability impacts on inverter-based resources (IBR).
- NERC issued a Level 2 alert[11] was issued March 14, 2023, on IBR issues.[12]
- Reliability Standard[13] modifications are in progress for PRC-024, MOD-025, MOD-026, MOD-027, FAC-001, FAC-002, PRC-002, PRC-019, and EOP-004.
- NERC published multiple guidelines and resources.[14]
- Immediate industry action is necessary to implement published guidelines and ensure reliable operation of the BPS with the increasing penetration of IBRs.
- IBR modeling requirements need significant improvement to ensure that high-quality, accurate models are used during reliability studies so performance issues can be identified before they occur during real-time operations.

[9] FERC - NERC - Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States
[10] https://www.nerc.com/pa/RAPA/PA/Pages/Section1600DataRequests.aspx
[11] https://www.nerc.com/pa/rrm/bpsa/Pages/About-Alerts.aspx
[12] NERC Level 2 alert issued March 14, 2023 on IBR issues
[13] https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx
[14] Quick Reference Guide on IBR Activities

Key Finding 3
Security Threats
Physical and cyber security attacks are increasing, reinforcing the need for further development and adaptation of standards and guidelines.

Physical and cyber security are essential to BPS reliability, and security is becoming increasingly important in the ongoing grid transformation. The growing attack surfaces that result from the increasing penetration of distributed energy resources call for ongoing development and the adaptation of cyber and physical security standards and guidelines to keep up with the ever-changing threat landscape. Furthermore, cyber-informed planning should include designs and be considered when planning and integrating the technologies into the grid to strengthen the cyber robustness.[15]

Hostile nation-states persist in targeting North American critical infrastructure, constantly evolving their methods to compromise the grid's reliability, resilience, and security. Domestic extremists have demonstrated the intent to attack the electricity infrastructure and take violent action against grid assets. The Cyber and Physical Security section of **Chapter 4** provides more information on these topics.

Resultant Actions

- The E-ISAC continues to enhance and distribute industry threat intelligence and work with government and industry partners to mitigate risks and provide guidance as threats arise.
- Through coordination and collaboration with the ERO Enterprise and industry stakeholders, NERC will provide insightful white paper guidance, implement robust security strategies, and continue to refine and adapt critical standards about cyber-informed engineering design to ensure a reliable and secure BPS. These efforts will enable industry to be better positioned against physical and cyber threats now and in the future.

Key Finding 4
Transmission System Reliability
The BES Transmission System continues to demonstrate significantly improved reliability for the fifth year in a row.

The overall severity of outages to the transmission system continues to show improvement over the last five years. Unavailability of alternating current (ac) circuits in 2022 was the lowest it has been for the last four years, the number of outages due to failed ac substation equipment and protection system equipment both decreased, and the average daily performance was better than the prior four years for spring, summer, and fall.

Despite Hurricane Ian having a secondary landfall on the East Coast two days after impacting Florida, the effective restoration (95%) of the BES was completed within 3.8 days. This demonstrated the value of ongoing utility coordination and grid-hardening efforts.[16] Hard-to-predict high-wind and lightning systems, such as severe thunderstorms and tornadoes, continue to be the most regular notable challenge for the system. The single most impactful day to the transmission system in 2022 occurred during Winter Storm Elliott, which will be detailed in the upcoming NERC and FERC joint report that is expected in late 2023.

[15] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/ERO_Enterprise_Whitepaper_Cyber_Planning_2023.pdf
[16] A lessons learned on hardening will be posted to NERC's Lessons Learned page later this year: https://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx.

Figure KF.1 highlights a few key numbers and facts about the North American BPS.

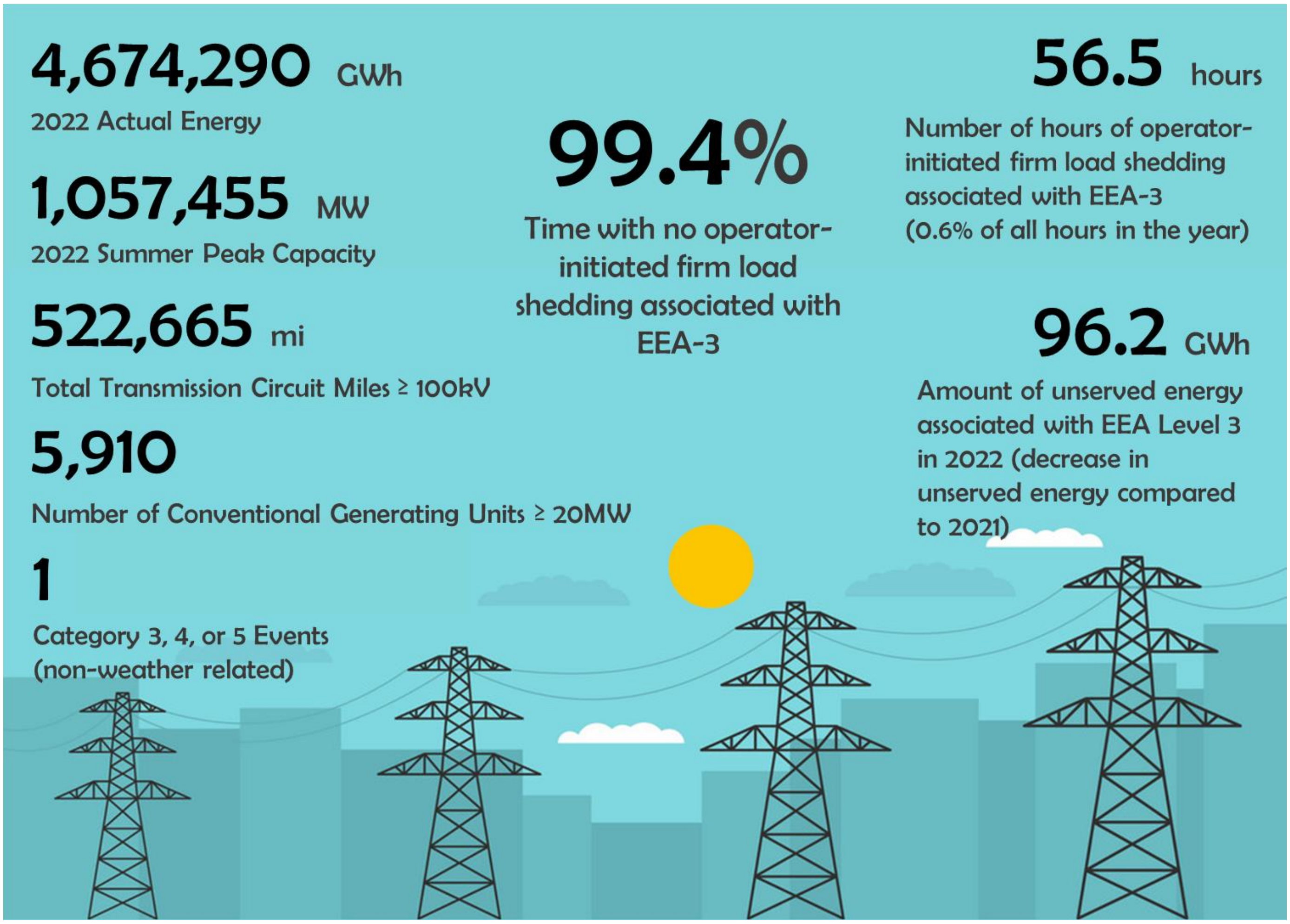

Figure KF.1: 2022 BPS Inventory and Performance Statistics

Chapter 1: Key Occurrences for 2022

Extreme weather, recurring systemic issues with wind and solar PV IBRs, and security threats (both physical and cyber) contributed to a number of events that impacted adversely upon BES reliability, increasing the amount of unserved energy year to year. Extreme weather events in 2022 included the September heat dome in California and other western areas, the western drought, Hurricane Ian, and the Winter Storm Elliott. Systemic issues with solar PV IBRs' inability to ride through momentary events on the transmission system continued, resulting in hundreds of MWs of supply from smaller, individual solar PV generation facilities tripping off-line at the same time. Through all of this, BES planners and operators continued to manage risks from cyber security threats and supply chain issues.

Extreme Weather Events

Overall, the BPS was reliable[17] throughout 2022. However, extreme weather events continue to pose the greatest risk to reliability due to the increase in frequency, footprint, duration; NERC's *ERO Reliability Risk Priorities Report*[18] identified extreme events, including extreme weather, as one of the four risk groupings that are seen as evolving risks to reliability. In late 2022, NERC identified extreme weather, especially for prolonged periods of time, as a risk in the *2022 LTRA*[19] and recommended that entities include the impact of extreme weather in their planning scenarios to ensure there are sufficient resources to meet these higher than normal load conditions during times when increased generation outages may occur.

In 2022, the National Oceanic and Atmospheric Administration (NOAA) identified 18 separate billion-dollar weather-related disasters in the United States (see **Figure 1.1)**. Additionally, one such disaster occurred in Canada.[20] Thirteen of these events affected the performance observed on the days with the most significant reliability impacts on generation, transmission, and loss of customer load (as measured by the SRI[21]).

Notably, the most significant reliability event of the year was Winter Storm Elliot, which swept over the majority of the Central and Eastern United States in December 2022. The severity of this event led FERC and NERC to form a joint inquiry with the Regional Entities that is currently underway.

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[17] Learn About NERC provides background information about NERC, the definition of reliability, and understanding the grid.
[18] NERC's ERO Reliability Risk Priorities Report
[19] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf
[20] Severe weather in Canada caused $3.1 billion in insured damages in 2022.
[21] The Severity Risk Index is a daily metric where transmission, generation, and load loss events aggregate into a single value that indicates the performance of the BES:
https://www.nerc.com/comm/PC/Performance%20Analysis%20Subcommittee%20PAS%202013/SRI_Enhancements_October_2020.pdf

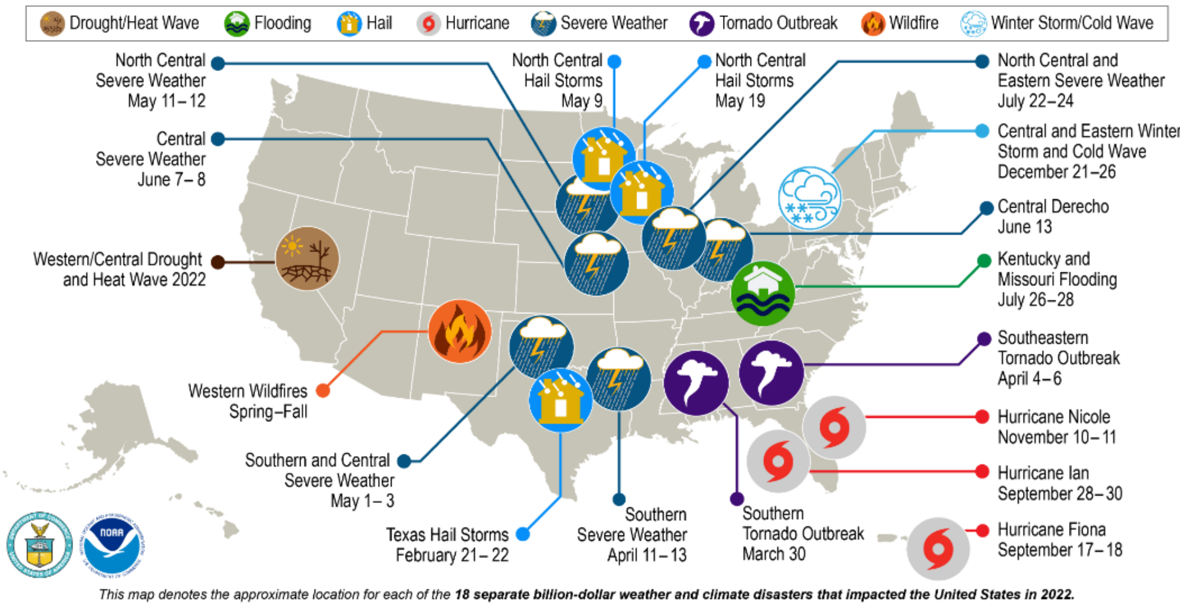

Figure 1.1: 2022 U.S. Billion-Dollar Weather and Climate Disasters[22]

September Heat Dome

Weather events are typically localized, so high demand in one area can be satisfied through excess capacity from other areas. However, recent widespread extreme weather and climate conditions have tested that assumption with many demand records being set in 2022.

From August 31 through September 10, 2022, the Western Interconnection experienced a heat wave that affected several states. In California, temperatures reached the mid-110s°F with Sacramento setting a record of 116°F. Throughout this period, afternoon highs were 15–30°F higher than average with nearly 1,000 cities in the U.S. West reporting heat records.[23] This occurrence was the most extreme heatwave in this part of the country this late in the season. The heat wave peaked on September 6, setting a new record high demand for the Western Interconnection of 16.753 GW. This was 5 GW greater than the previous record set in 2020. The heat dome resulted in seven EEA-3 alerts; however, energy conservation, demand-side management, and other measures enabled Balancing Authorities (BA) to operate through the period without shedding firm load.

In June, a prolonged heat wave and a derecho swept across the Midwest and southern half of the United States, contributing to the hottest June in 128 years.[24] As daily temperatures in the high-90s°F were sustained, increased demand in combination with high winds strained the BES. These conditions contributed to a large number of generator outages and a large amount of load loss from June 13–15, making these the third, fourth, and sixth worst SRI days in 2022. While these events did not receive the same press attention as Winter Storm Elliott, they clearly signal that the ongoing risk of extreme weather to the BES, specifically generation, is not limited to cold weather.

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[22] NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2023). https://https://www.ncei.noaa.gov/access/billions/, DOI: 10.25921/stkw-7w73

[23] https://www.washingtonpost.com/climate-environment/2022/09/08/western-heatwave-records-california-climate/

[24] https://www.noaa.gov/news/june-2022-us-dominated-by-remarkable-heat-dryness

Hurricane Ian

On September 28, Hurricane Ian made landfall on the West Coast of Florida with sustained winds of 155 mph.[25] For context, Category 5 hurricanes start at 157 mph winds, so Hurricane Ian is considered one of the strongest and deadliest hurricanes in Florida's history. Hurricane Ian slowly crossed Florida, causing significant inland flooding across the southwest, central, and eastern portions of the state with widespread rainfall totals of 10–20 inches. The counties of Volusia, Orange, Seminole, and Brevard reported more than 20 inches of rainfall each.

After moving across Florida, damaging coastal communities with strong winds and storm surge, Hurricane Ian re-emerged into the Atlantic, strengthening again and making a second landfall on September 30, near Georgetown, South Carolina, with sustained winds of 85 miles per hour (see **Figure 1.2**). The storm caused over three million customer outages in Florida, the Carolinas, and Virginia and caused widespread damage across the Southeast United States. Results of a resilience and transmission restoration analysis for Hurricane Ian can be found in **Chapter 2**.

Figure 1.2: Path of Hurricane Ian

Western Long-Term Drought

The multi-year Western U.S. drought resulted in water shortages across many locations in 2022.

The nation's two largest reservoirs, Lake Mead and Lake Powell, are reporting the lowest water levels since filled, at less than 30% of their capacity (see **Figure 1.3**). In 2022, the Bureau of Reclamation reduced the water available for use by the seven states served by the Colorado River watershed to prevent a catastrophic reduction in water levels.

The dams for these two reservoirs, Hoover and Glen Canyon, are major power producers for this part of the Western Interconnection with a combined capacity of more than 3,300 MW. Continued drought could drop water levels below the intake pipes, which would bring power generation to a stop. The potential loss of these dispatchable resources could introduce operational challenges when system demand is high.

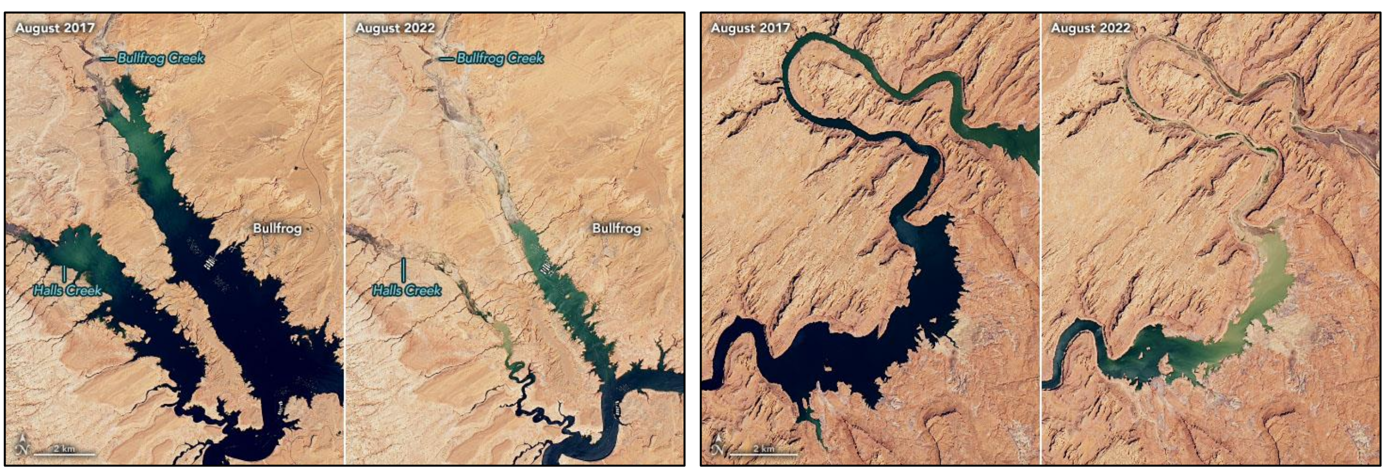


Figure 1.3: Five-Year Comparisons of Lake Powell (left) and Lake Mead (right)[26]

[25] **Figure 1.2**, Path of Hurricane Ian, Weather.com
[26] https://earthobservatory.nasa.gov/images/150249/lake-powell-still-shrinking

In 2022, California experienced the driest January, February, and March on record. In May, when reservoir levels should be at their highest, the state's two largest reservoirs, Shasta Lake and Lake Oroville, were already at critically low levels. Shasta ended the 2022 season at 31% capacity, 58% of the reservoir's average for that time of the year.[27]

This prolonged drought has widespread impacts on multiple sectors, including (but not limited to) agriculture, water utilities, manufacturing, and energy. Fire conditions are also worsening for these areas.

The 2022–2023 winter was much wetter than average for much of the Western Interconnection. While this wet season improved reservoirs levels throughout much of the West, it is too early to determine long-term improvements for the area.

Winter Storm Elliott

As early as December 16, 2022, extreme cold temperatures were forecasted to move from the Pacific Northwest down and across the United States, bringing extreme cold temperatures, strong winds, and precipitation to much of the lower 48 states (see **Figure 1.4** and **Figure 1.5**). As electric utilities began preparing for the cold weather event, they implemented actions from their winter plans with many calling for conservative operations, cancelling planned outages that were scheduled to begin during this time, and issuing cold weather alerts.

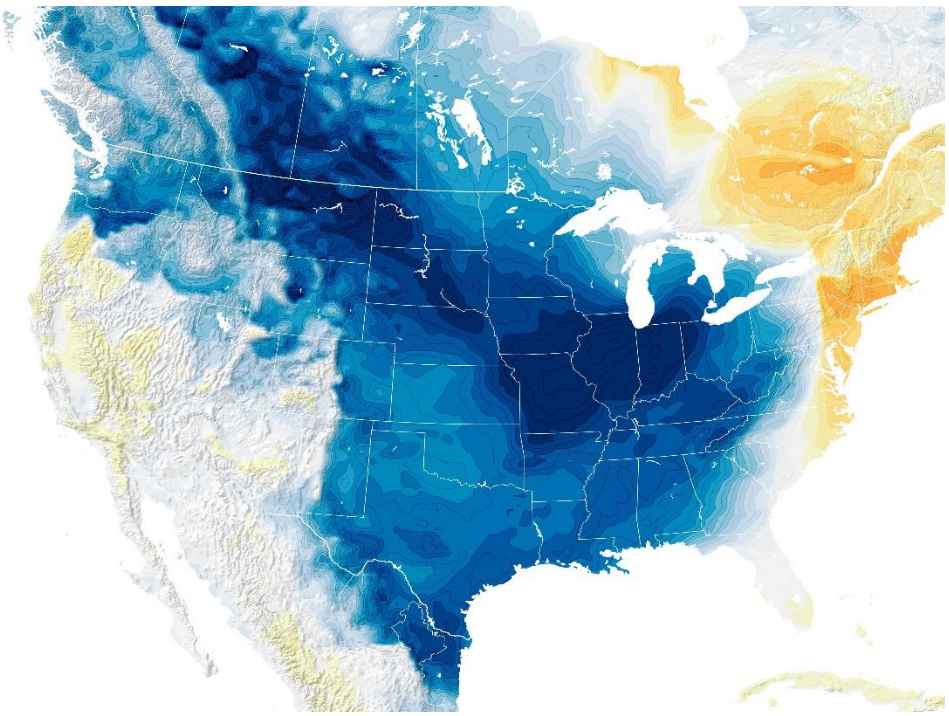


Figure 1.4: The Predicted Path of Winter Storm Elliott[28]

As the winter weather moved across the country, temperatures dropped dramatically. In many areas, resulting loads were higher than forecasted. Like winter storm events in 2018 and 2021, a significant numbers of generator outages occurred, and entities that were relying on purchases from other areas found those imports were not available in real-time.

[27] California's two largest reservoirs are at 'critically low' levels - Los Angeles Times
[28] Predicted path of Winter Storm Elliott

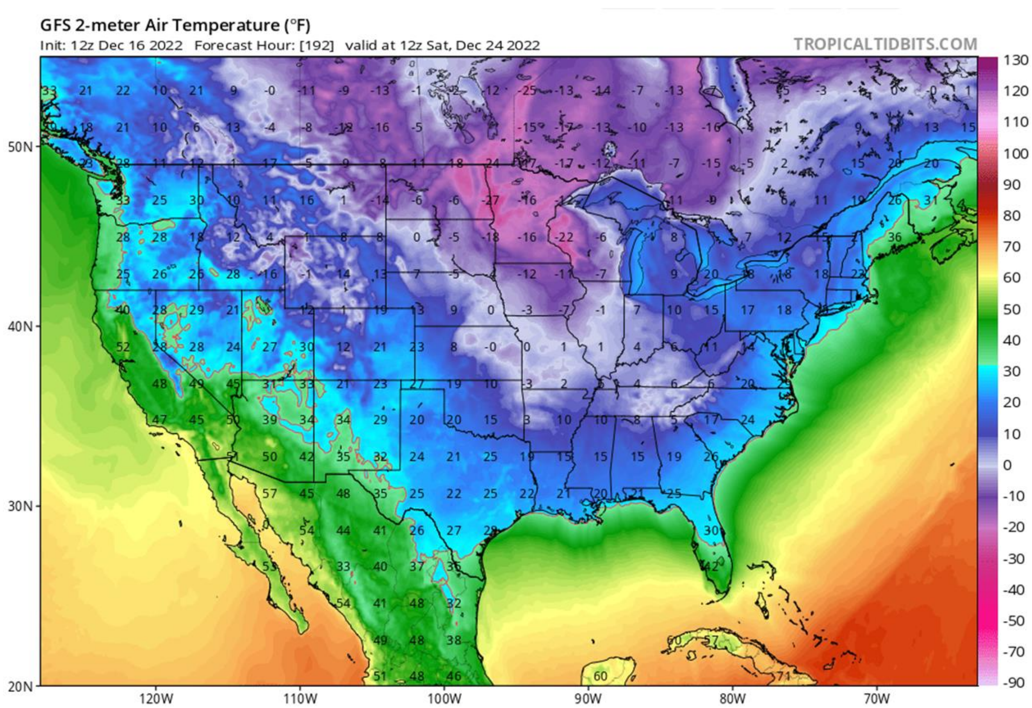


Figure 1.5: Temperatures across the United States Predicted for December 24, 2022[29]

Winter Storm Elliott rapidly intensified into December 23 and the holiday weekend. Temperatures dropped between 30–50°F in a 24-hour period, reaching temperatures significantly colder than seasonal averages with the freeze line going all the way down to Mobile Bay, Alabama, and across Central Florida. Strong winds and extreme cold temperatures affected two-thirds of the lower 48 states, reaching its worst point between December 23 and December 26. Wind gusts were reported above 79 mph with the highest recorded wind speeds for Winter Storm Elliott of 151 mph. Because of the rapid intensification of the storm, it was considered a bomb cyclone, an area of low pressure that intensifies quickly.

As supply tightened, many areas declared EEAs, made public appeals for conservation, and implemented steps in their energy emergency plans for capacity and energy emergencies. Tennessee, Kentucky, North Carolina, and South Carolina experienced operator-controlled load shed. Around 2.1 million customers experienced power interruptions during this event. On December 28, NERC and FERC announced the formation of a joint inquiry team to better understand the event. The team has been formed and has begun the effort of gathering data and performing analysis to understand the effects of the event on the BPS and provide recommendations to address cold weather reliability going forward. The report is expected in late 2023.

[29] https://www.tropicaltidbits.com/analysis/models/?model=gfs

Texas Loss of Solar PV

Grid disturbances on the BPS continue to result in undesired outages of BPS-connected solar PV resources. On June 4, 2022, widespread reductions of solar PV resource power output occurred near Odessa, Texas, in the Texas Interconnection due to an inability to “ride through” these disturbances. **Figure 1.6** shows the location and MW loss (bubble size) of the effected solar PV plants (**red**) compared to effected conventional generation (**blue**). As stated in the key finding, this event is nearly identical to an event that occurred just over one year prior at the same location. This event is a perfect illustration of the need for immediate industry action to ensure reliable operation of the BPS with the increasing penetration of IBRs. The unexpected and unplanned loss of generation (both synchronous and inverter-based) poses an increasing and significant risk to BPS reliability.

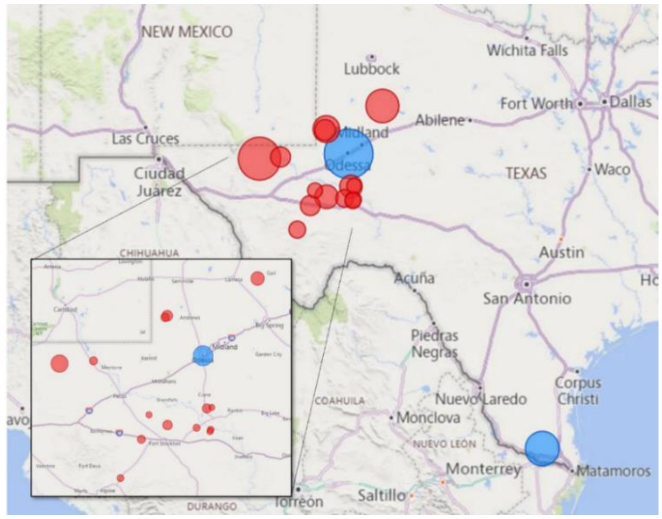


Figure 1.6: 2022 Impact of Odessa Disturbance

This event, titled the 2022 Odessa Disturbance, is the subject of the December 2022 Joint NERC Texas RE Staff Report.[30] The initiating event was a single-line-to-ground fault at a 345 kV substation near Odessa, Texas, which then lead to an erroneous loss of an additional 511 MW of synchronous generation and an unexpected loss of over 1,700 MW of reduced output from solar PV facilities up to several hundred miles away from the location of the initiating event. This was assessed as a Category 3a event in the NERC Event Analysis Process, the first Category 3 or higher since 2018.

The size of this disturbance nearly exceeded the Texas Interconnection RLPC defined in NERC Reliability Standard BAL-003, which is used to establish the largest credible contingency for frequency stability in an Interconnection. Furthermore, this disturbance involved the abnormal performance of multiple solar PV facilities and synchronous generating facilities. These types of concurrent and unexpected losses in generation pose a significant risk to BPS reliability. Many of the underlying causes of abnormal performance are systemic in nature and not mitigatable in a timely manner. These causes can be captured in system planning assessments or interconnection studies. As the penetration of solar PV resources (and all IBRs) continues to grow rapidly in the ERCOT footprint and many areas of North America, it is paramount that these IBR performance issues are proactively and immediately addressed.

Like the previous Odessa disturbances in May and June 2021, the June 2022 event in Texas was mainly attributed to abnormal performance of the inverter controls, plant controls, and protections within the facility.

This event continues to highlight the criticality of ensuring a reliable resource mix that is able to support the BPS by providing essential reliability services, including during contingency events. The December 2022 Joint NERC Texas RE Staff Report highlights multiple notable areas for improvement moving forward:

- There is an immediate need for all Generator Owners (GO), especially those affected in this event, to mitigate abnormal performance issues in the Texas Interconnection.
- The risk profile for IBR performance issues needs to be elevated, and immediate ERO Enterprise risk-based compliance activities are needed in this area.
- There is an immediate need for a comprehensive performance-based generator ride-through standard.
- There is a need for electromagnetic transient modeling requirements and accurate electromagnetic transient models for all BPS-connected IBRs. Comprehensive model quality reviews should also take place.

[30] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/NERC_2022_Odessa_Disturbance_Report%20(1).pdf

Severity Risk Index[31]

The SRI measures the severity of daily conditions based on the combined impact of load loss, loss of generation, and loss of transmission on the BPS. The SRI provides a quantitative measure that assesses the relative severity of these events on a daily basis, and it provides a comprehensive picture of the performance of the BPS and allows NERC to assess year-on-year trends of its reliability. For 2022, load loss data voluntarily reported to the IEEE Distribution Reliability Working Group was used to estimate the daily load loss component.

Figure 2.1 plots the daily SRI scores for 2022 against control limits that were calculated by using 2018–2021 seasonal daily performance. On a daily basis, a general normal range of performance exists, visible by the gray-colored band or within the daily seasonal 90% control limits.[32] Days of stress on the system are identified by those that extend above the seasonal daily control limits. The top 10 days of 2022 are labeled with the rank of severity.

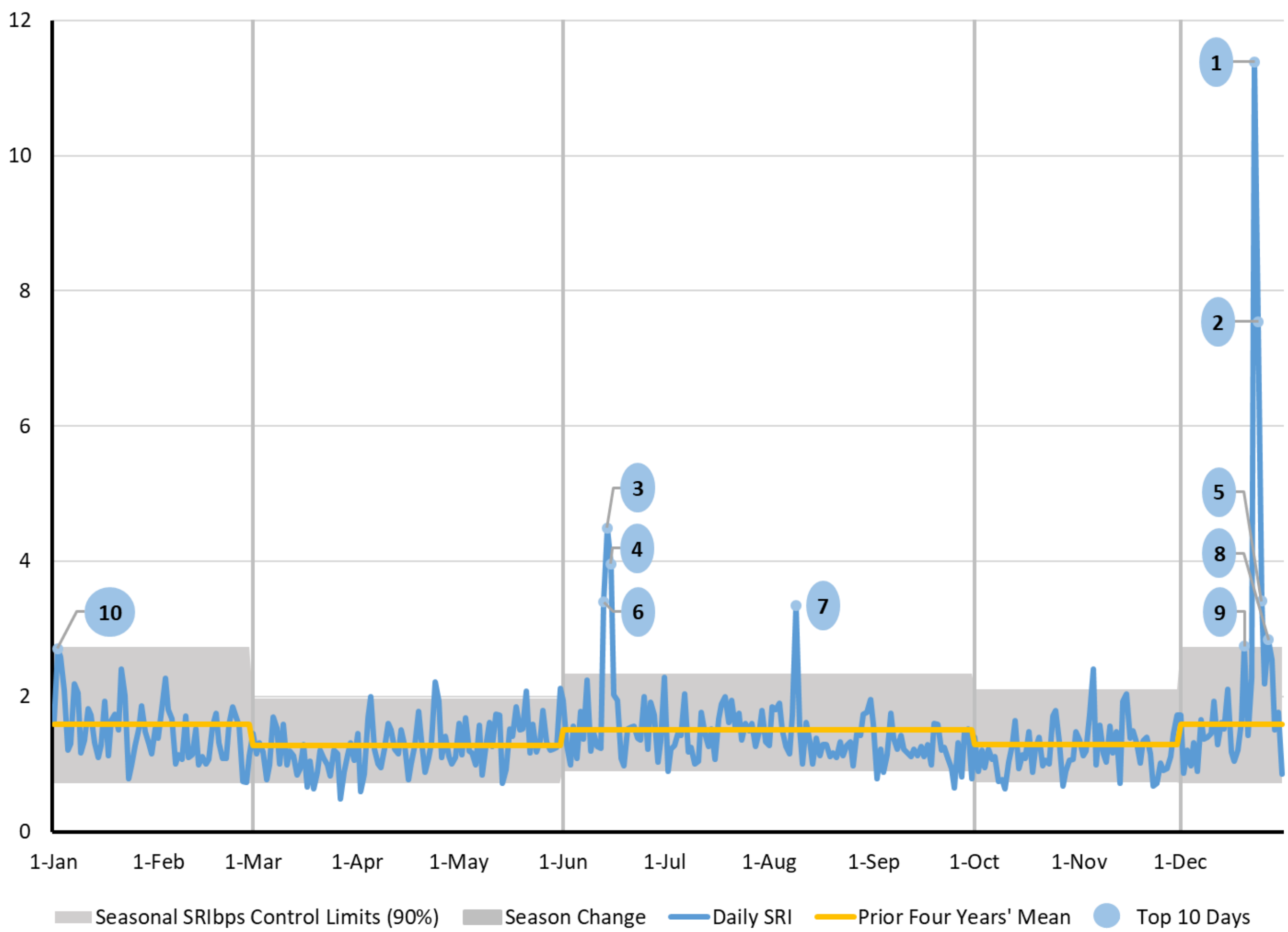


Figure 2.1: 2022 Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

Table 2.1 provides details of the scores for the top 10 SRI days during 2022. The table includes whether notably atypical weather conditions were ongoing during the day and their general location by Regional Entity. All of the top 10 SRI days in 2022 occurred during some type of atypical weather occurrence: six occurred during the December and January cold weather events and four during widespread high temperatures in conjunction with thunderstorm systems.

[31] Severity Risk Index

[32] The shaded area reflects the 90% confidence interval (CI) of the historic values is between the 5th percentile and the 95th percentile.

Table 2.1: 2022 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components 2022				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	December 23	11.39	8.27	0.86	2.26	Winter Storm Elliott	All
2	December 24	7.54	6.52	0.97	0.05	Winter Storm Elliott	All
3	June 14	4.49	1.53	0.39	2.57	High Temperatures and Derecho	MRO, NPCC, RF, SERC, Texas RE
4	June 15	3.96	1.55	0.20	2.21	High Temperatures and Derecho	MRO, NPCC, RF, SERC, Texas RE
5	December 25	3.41	3.18	0.10	0.13	Winter Storm Elliott	All
6	June 13	3.40	2.43	0.10	0.87	High Temperatures and Derecho	MRO, NPCC, RF, SERC, Texas RE
7	August 9	3.35	1.82	0.32	1.21	High Temperatures and Thunderstorms	MRO, NPCC, RF, Texas RE
8	December 27	2.84	1.80	0.28	0.76	Winter Storm Elliott	All
9	December 20	2.74	1.70	0.19	0.85	Winter Storm Elliott	All
10	January 2	2.71	2.17	0.14	0.39	Winter Storm	MRO, Texas RE

SRI Performance Trends

Performance trends can be recognized by comparing the last year's top SRI days to those of prior years. **Figure 2.2** shows the top 10 SRI days for each of the past five years in descending rank order. Three of the top 10 SRI days in the last five years occurred in 2022 with only the February 2021 winter storm being worse. Two of the days are attributable to Winter Storm Elliot; the third day is to high temperatures in tandem with a derecho.

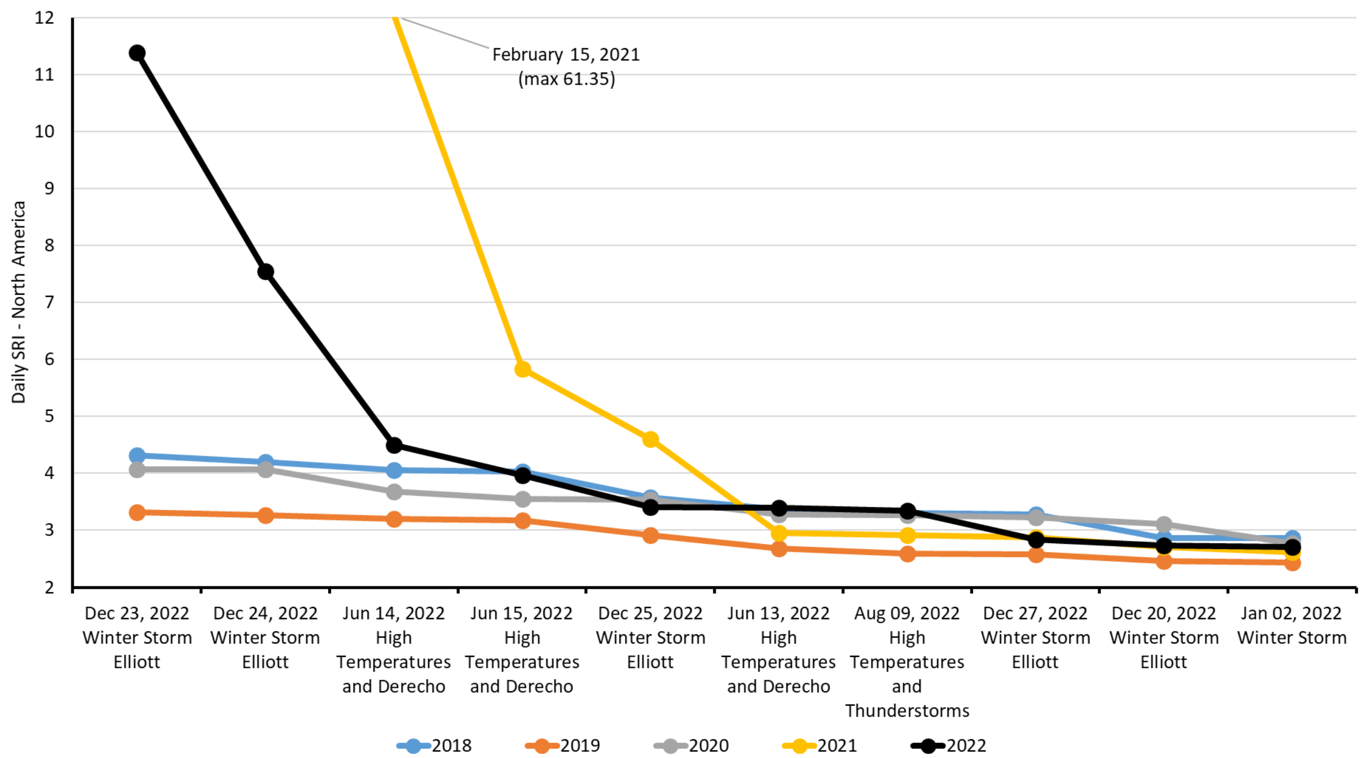


Figure 2.2: Top Annual Daily SRI Days Sorted Descending

To put the severity of days in 2022 into context with historic BPS performance, the top 10 days over the five-year period are updated annually. Table 2.2 identifies the top 10 SRI days occurring for 2018–2022 with the contribution of the generation, transmission, and load loss components to the SRI for each day; contributing event information; and the Regional Entities impacted by the event. Three of the top 10 SRI days occurred in 2022, only being surpassed by the February 2021 cold weather event. The top eight days all occurred within the last two years, seven of which were due to cold-weather-related events.

Table 2.2: 2018–2022 Top 10 SRI Days

Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entity
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	February 15, 2021	61.36	5.54	0.80	55.02	Cold Weather Event	MRO, RF, SERC, Texas RE
2	February 16, 2021	18.34	5.02	0.54	12.78	Cold Weather Event	MRO, RF, SERC, Texas RE
3	February 17, 2021	12.04	2.49	0.29	9.26	Cold Weather Event	MRO, RF, SERC, Texas RE
4	**December 23, 2022**	**11.39**	**8.27**	**0.86**	**2.26**	**Winter Storm Elliott**	**All**
5	**December 24, 2022**	**7.54**	**6.52**	**0.97**	**0.05**	**Winter Storm Elliott**	**All**
6	February 18, 2021	5.83	2.20	0.33	3.30	Cold Weather Event	MRO, RF, SERC, Texas RE

Table 2.2: 2018–2022 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entity
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
7	February 14, 2021	4.60	1.91	0.86	1.83	Cold Weather Event	MRO, RF, SERC, Texas RE
8	**June 14, 2022**	**4.49**	**1.53**	**0.39**	**2.57**	**High Temperatures and Derecho**	**MRO, NPCC, RF, SERC, Texas RE**
9	September 14, 2018	4.32	1.34	0.44	2.53	Hurricane Florence	SERC
10	March 2, 2018	4.19	0.90	0.39	2.90	Winter Storm Riley	NPCC

The cumulative performance of the BPS is calculated by summing each day's SRI for the year. **Table 2.3** shows the annual cumulative SRI for the five-year period of 2018–2022. For this period, 2022 as a whole was not statistically significantly different from any of the other four years. The year of 2022 saw improving transmission system performance compared to previous years, statistically similar load loss to all years except 2021, and statistically worse load loss than all years except 2018.

Table 2.3: Annual Cumulative SRI					
Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2018	389.9	71.2	68.4	529.5	1.45
2019	368.9	67.6	57.0	493.5	1.35
2020	339.0	67.9	72.5	479.4	1.31
2021	375.8	65.5	152.1	593.4	1.63
2022	407.6	61.3	55.2	524.1	1.44

Impact of Extreme Event Days

Extreme Event Days

Extreme event days are identified as events above the 95th percentile upper bound relative to the past four years' severity measures for any season within North America or a specified Interconnection. This analysis expands on the transmission and generation components that contribute to the SRI reported in the previous **SRI Performance Trends** section to explore the causes of the extreme days.

The response to the impacts of extreme days on BES resources is characterized by the amount of transmission or generation reporting immediate forced outages or derates starting on a given day. By analyzing the impact and causes of extreme event days, it is possible to identify which conditions pose the highest risk to the BES. While this analysis does not address every potential scenario, learning from performance during extreme events helps provide insight into how the system may respond to a range of conditions and events.

Extreme day outages for transmission and generation by Interconnection are presented for North America in **Appendix A**, Supplemental Analysis by Interconnection.[33] The analysis listed in the following subsections is reported

[33] For extreme day Interconnection-level analysis, the QI is included in the analysis labeled as EI–QI.

separately for transmission and generation. The total estimated megavolt-amperes (MVA) transfer capacity reported in the TADS or net maximum capacity reported to GADS for North America or by Interconnection is shown at the top of each figure in this chapter.

Transmission Impacted

In 2022, 11 days qualified as extreme transmission days for the BPS as compared to 17 in 2021. On these days, the aggregated potential MVA capacity impacted due to automatic transmission outages was 2.4–5.8 times as high as the associated season's average, which is between 0.056% and 0.061% of total MVA capacity across North America, depending on the season. Weather (Excluding Lightning) (312 outages) was the primary initiating cause code reported for events on these extreme days. Several other initiating cause codes had more than 40 outages: Failed AC Circuit Equipment (87), Unknown (78), Vegetation (51), Failed AC Substation Equipment (48), Lightning (45), and Foreign Interference (41). In 2022, the most extreme transmission-impacting day was on December 24, primarily due to Winter Storm Elliot (see **Figure 2.3**).

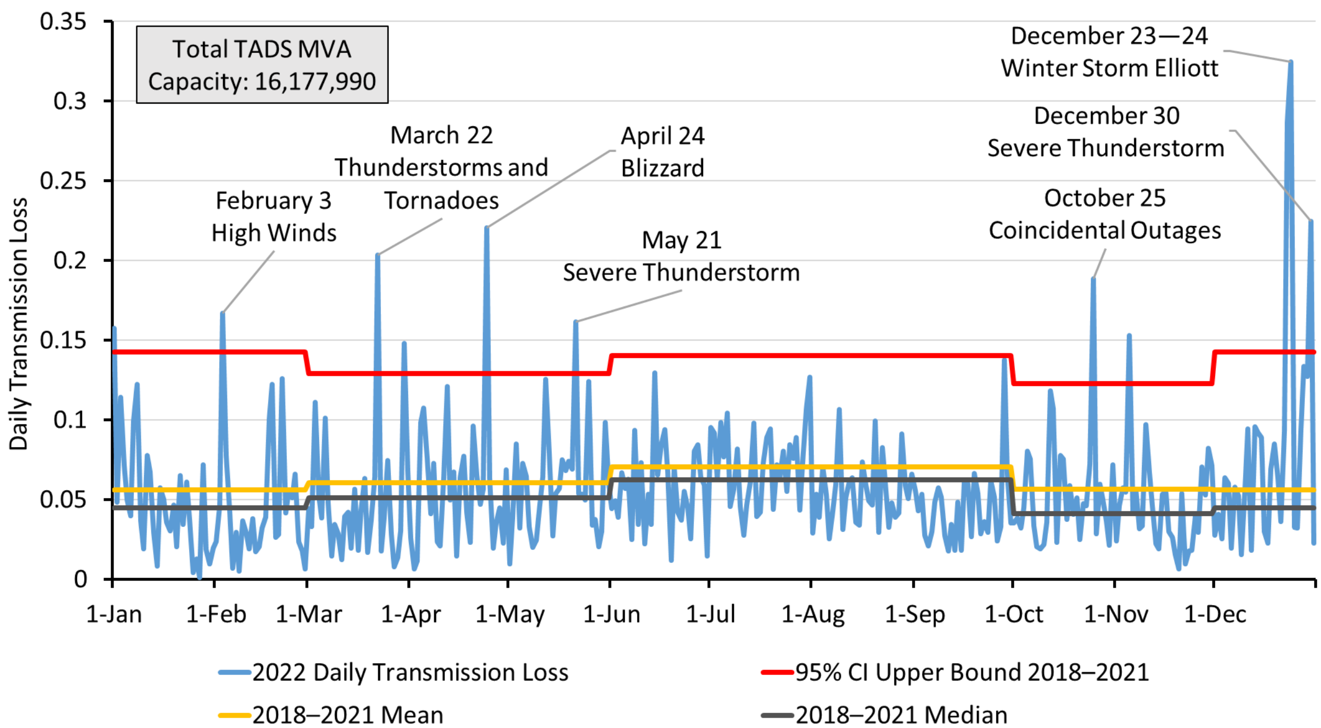


Figure 2.3: 2022 Transmission Outages during Extreme Days

The top causes reported for outages that occurred on extreme days are shown in rank order as a whole and for each Interconnection. Weather (Excluding Lightning), Failed AC Substation Equipment, and Unknown were the top three causes for transmission systems (**Table 2.4**).

Table 2.4: Top Transmission Initiating Outage Causes on Extreme Days

Area	Cause #1	Cause #2	Cause #3	Cause #4	Cause #5
North America	Weather (Excluding Lightning)	Failed AC Substation Equipment	Unknown	Failed AC Circuit Equipment	Contamination
Eastern–Québec Interconnections	Weather (Excluding Lightning)	Unknown	Lightning	Failed AC Circuit Equipment	Contamination

Table 2.4: Top Transmission Initiating Outage Causes on Extreme Days					
Area	**Cause #1**	**Cause #2**	**Cause #3**	**Cause #4**	**Cause #5**
Texas Interconnection	Weather (Excluding Lightning)	Failed AC Substation Equipment	Unknown	Failed AC Circuit Equipment	Lightning
Western Interconnection	Weather (Excluding Lightning)	Fire	Failed AC Substation Equipment	Unknown	Failed AC Circuit Equipment

Conventional Generation Impacted

Based on analysis of GADS data, a total of 22 days in 2022 qualified as extreme for North America's BES (see **Figure 2.4**), compared to 17 in 2021. Two extreme generation loss days coincided with extreme days identified for transmission (December 23 and 24). On these days, the generation portion of the BES experienced outages that were 1.5–7.9 times as severe as the associated season's average, which is 0.92% to 1.08% of total generating capacity. Seven of the days align with various cold weather events and four to various hot weather events. The days where generation outages were slightly above the seasonal bounds (**red** line) do not have a specific cause listed and have been investigated; they either coincided with severe thunderstorms (March 10, May 13, and June 15) or were a large number of apparent coincidental outages with no apparent adverse conditions.

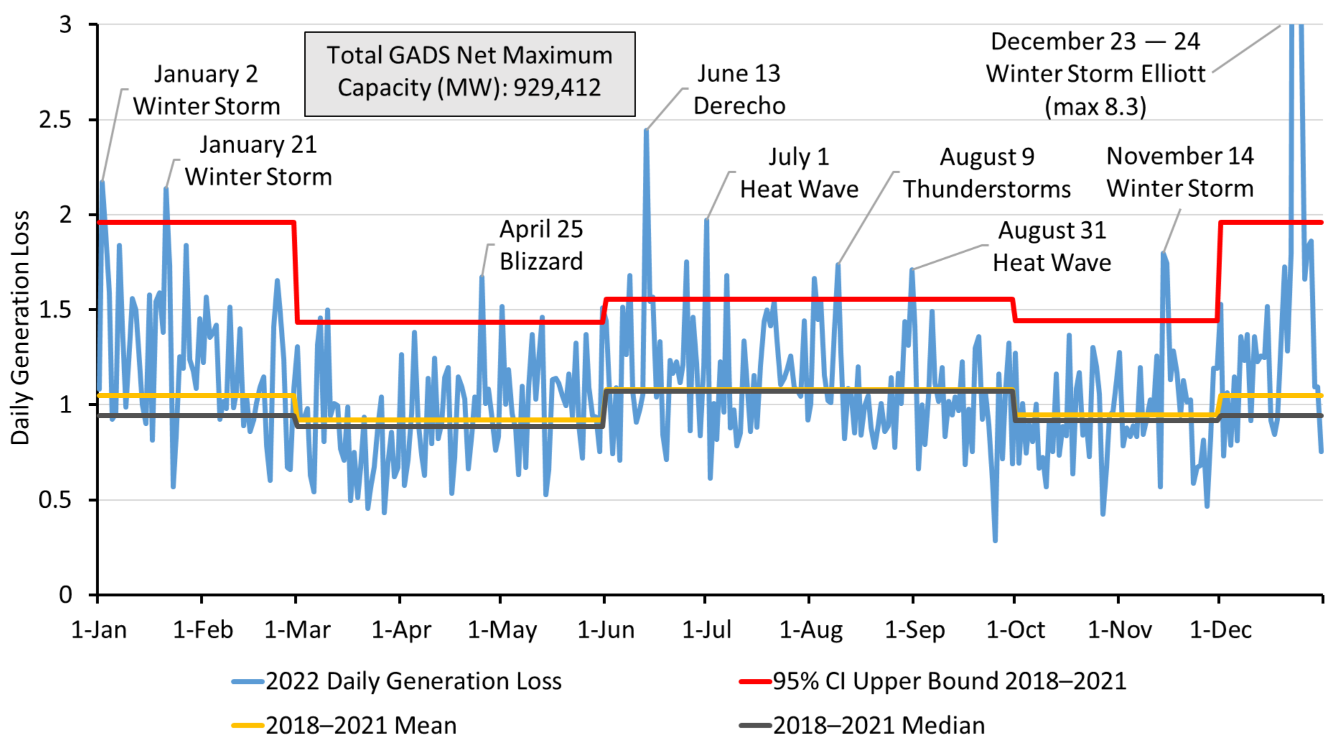


Figure 2.4: 2022 Generation Impacted during Extreme Days

The primary cause codes of generation outages reported on extreme days were equipment-related to Fuel/Ignition/Combustion Systems, Auxiliary Systems, and Economic reasons to which all have been found to increase during major temperature-related events (**Table 2.5**). It should be noted that cause codes relating to lack of fuel, either due to contractual reasons or a physical fuel disruption, fall under the economic group as historically outages due to lack of fuel could be attributed to economic decisions. The re-categorization of these cause codes is under consideration given the shift in perspective over the last several years.

Table 2.5: Top Generation Outage Causes on Extreme Days					
Area	Cause #1	Cause #2	Cause #3	Cause #4	Cause #5
North America	Fuel, Ignition, and Combustion Systems	Auxiliary Systems	Economic	Boiler Tube Leaks	Electrical
Eastern–Québec Interconnections	Fuel, Ignition, and Combustion Systems	Economic	Auxiliary Systems	Boiler Tube Leaks	Electrical
Texas Interconnection	Fuel, Ignition, and Combustion Systems	Electrical	Auxiliary Systems	Boiler Air and Gas Systems	Boiler Tube Leaks
Western Interconnection	Electrical	Auxiliary Systems	Controls	Fuel, Ignition, and Combustion Systems	Miscellaneous (Balance of Plant)

Resilience against Extreme Weather

The analysis of large transmission events is based on outage and restoration processes for transmission elements, not on disruption and restoration of distribution customer load. Restoration of the transmission system to serve customer load is always the priority, and restoration of load generally takes place long before all transmission elements are returned to service.

The 2022 analysis identifies 10 large transmission events (events with 20 or more transmission element outages) caused by extreme weather and quantifies resilience and restoration statistics for them followed by a detailed description of Hurricane Ian as the largest outage event on transmission system. The resilience statistics enable the measurement and tracking of the ability of the transmission system to withstand, adapt, protect against, and recover during and after extreme weather events. Next, the multi-year statistics are calculated and studied by extreme weather type. Finally, changes in the statistics comparing 2017–2021 to 2018–2022 for each extreme weather type are identified and assessed by the analysis.

TADS Outage Grouping and 2022 Large Weather Events

An algorithm groups automatic outages reported in TADS based on Interconnection and associated start and end times.[34] The resulting transmission outage events are determined to be weather-related if at least one outage in the event is initiated or sustained by one of the following TADS cause codes: Weather (excluding lighting), Lightning, Fire, or Environmental. The procedure produces groupings of outages that are further reviewed and compared with the weather information from external sources to confirm or refine the events. In particular, Velocity Suite was used as a source of a utility company footprints, and weather sources like NOAA and Ventusky were used to visualize the weather events. Matching the data from these sources provides a much clearer picture of outages within the event. This combination of automatic and manual procedures results in a set of transmission events that can cross boundaries of different utilities and Regional Entities to capture significant events caused by extreme weather, such as hurricanes.

One of the 10 events identified, Hurricane Ian, has been analyzed as two sub-events: Florida and the U.S. East Coast. This is based on two distinct landfall impacts that occurred: the hurricane first made landfall in Florida then crossed Florida and regained strength over the Atlantic Ocean before making landfall again in South Carolina and traveling up the East Coast. Table 2.6 lists these events in chronological order and shows the severe weather type for each event with statistics that quantify the impact of the event on the system.

[34] S. Ekisheva, R. Rieder, J. Norris, M. Lauby, and I. Dobson, “Impact of extreme weather on North American transmission system outages,” 2021 IEEE Power & Energy Society General Meeting.

In 2022, the largest number of outages in a single event occurred in the Eastern Interconnection with Hurricane Ian, which started on September 27 (140 transmission outages reported); this is shown in **red** in **Table 2.6**. Other storms of note are the April 23 Blizzard (117 transmission outages reported) and Winter Storm Elliot (100 transmission outages reported). The definition of element-days lost is provided in Appendix B the 2022 SOR.[35] It is noteworthy that Hurricane Nicole, which was the only other hurricane from a list of 2022 U.S. billion dollar weather and climate disasters that affected a NERC Regional Entity (see **Figure 1.1**), caused a relatively small transmission event of nine outages and thus is not listed in **Table 2.6**.

Table 2.6: 2022 Large Transmission Weather-Related Events

Event Start	Event Outage Count			Interconnection	Extreme/Severe Weather Event	Transmission Capacity Affected (MVA)	Miles Affected	Duration (Days)	Element-Days Lost
	All Automatic	Sustained Automatic	Momentary Automatic						
January 2	31	27	4	Eastern	Winter storm with high winds	10,250	774	3.7	10
February 17	55	44	11	Eastern	Winter storm, snow, freezing rain	26,004	1,454	46.3	74
March 20	54	47	7	Eastern	Tornado, damaging winds	21,680	2,349	9.6	41
April 23	117	92	25	Eastern	Blizzard	46,937	8,195	25.8	72
May 12	32	28	4	Eastern	Severe thunderstorm, wind	13,052	1,287	7	64
May 21	34	29	5	Eastern	Thunderstorm	17,110	1,763	42.9	90
June 13	83	67	16	Eastern	Central Derecho	39,593	2,597	25.7	87
September 27	**140**	**94**	**46**	**Eastern**	**Hurricane Ian**	**55,702**	**2,455**	**14.6**	**54**
September 27	99	66	33	Eastern	Hurricane Ian (Florida)	41,375	1,589	3.8	44
September 29	41	28	13	Eastern	Hurricane Ian (East Coast)	14,327	866	12.9	10
November 4	43	40	3	Western	Pacific winter storm	14,259	1,278	57.4	140
December 23	100	87	13	Eastern and Québec	Winter Storm Elliot	61,573	2,975	11.5	90.1

Outage, Restore, and Performance Curves

Table 2.6 illustrates the variability in event sizes and event duration. However, these statistics do not completely explain what happened during the events; the outage, restore, and performance curves of the events provide more details on how the events unfolded.[36] **Figure 2.5** serves as an example to describe transmission outages during an event, these curves track the number of elements out or the MVA capacity impact on the vertical axis versus time on the horizontal axis.

[35] NERC SOR 2022

[36] S. Ekisheva, I. Dobson, R. Rieder, and J. Norris, "Assessing transmission resilience during extreme weather with outage and restore processes," 2022 17th International Conference on Probabilistic Methods Applied to Power Systems

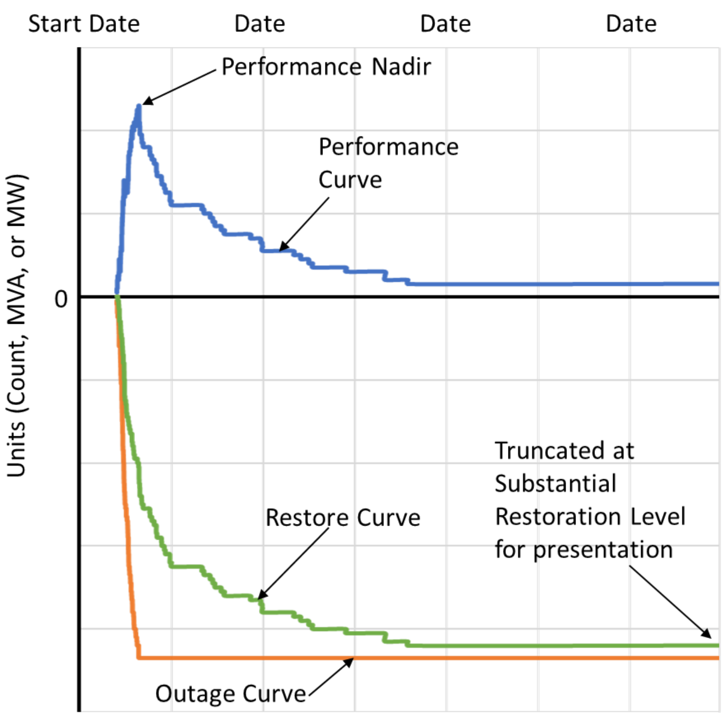


Figure 2.5: Example of Outage, Restore, and Performance Curves for a Large Transmission or Generation Event

The outage curve is the cumulative number of elements, cumulative equivalent MVA capacity impact, or cumulative generation out at the time shown on the horizontal axis.

The restore curve is the cumulative number of elements restored, cumulative equivalent MVA restored, or cumulative generation restored at the time shown on the horizontal axis.

Lastly, the performance curve is the number of elements or equivalent MVA capacity impact out simultaneously at the time shown on the horizontal axis. The value is equal to elements or MVA capacity restored minus the elements or MVA capacity (i.e., the performance curve is the restore curve minus the outage curve). The performance curve combines the degradation and recovery phases of the event.

The curves enable the calculation of several resilience metrics.[37] These metrics help to quantify the abilities of a resilient power system to effectively absorb, withstand, adapt, and protect against extreme weather (event size, outage process duration and outage rate, time to first restore, the most degraded state in the event, the total element-days and MVA capacity-days lost) as well as to recover, reduce duration, and reduce impact of extreme weather (event duration, time to first restore, time to substantial restoration, instantaneous restore rate).

Resilience Analysis of Hurricane Ian as a Large Transmission Event

Transmission Curves and Statistics for Hurricane Ian

Hurricanes cause the largest, longest, and most impactful events on the transmission system (as measured by element- and MVA capacity-days lost). Hurricane Ian was the largest transmission event in 2022 in terms of the number of outages and total MVA capacity affected with 140 automatic transmission outages reported by 11 TOs. These outages included 7 transformer outages and 133 ac circuit outages; 46 out of the 133 ac circuit outages were momentary (<1 minute), and the remaining were sustained. The impact of Hurricane Ian on MVA capacity was also significant with a total of 55,702 MVA capacity being affected. Although it was the largest event, it was a relatively short event for a hurricane, only the sixth longest event in 2022 in terms of overall duration. Because there was one unrestored outage with duration of 14.6 days before the event end, the element and MVA-based curves for Hurricane Ian in **Figure 2.6** through **Figure 2.9** are truncated at the 95% restoration level to better show significant changes in the outage, restore, and performance curves.

The transmission outage curves show that outages due to the storm system started approximately 20 hours before Hurricane Ian made landfall in Florida. Outages started occurring at a higher rate when Hurricane Ian made landfall, accumulating at a rate of 5.1 outages per hour (2,044 MVA capacity per hour). The maximum number of elements (31) and MVA capacity (13,515) simultaneously out, shown by the nadir of the respective performance curves, was reached approximately 27 hours into the event, and the system remained in this most degraded state for five minutes. The restore process started one minute from the event start with an automatic restore; the first manual restore occurred at 202 minutes and progressed steadily to recover 133 (95%) of the elements and 52,917 (95%) of

[37] Resilience statistics are defined in Appendix B in the 2022 SOR.

MVA affected by the hurricane after 3.84 days (or 26% of the total event duration). The total event losses calculated from the performance curves were 53.9 element-days and 22,001 MVA-days.

Hurricane Ian was one storm event with two distinct impacts on the area as well as two corresponding restoration efforts, one for Florida and one for the remainder of the East Coast. The transmission curves also show the topographical effect of the storm on the area. The outage curves rise sharply as the hurricane made landfall and passed over densely populated areas, flattening out as the storm passed over less densely populated areas and the ocean (see **Figure 2.6)**.

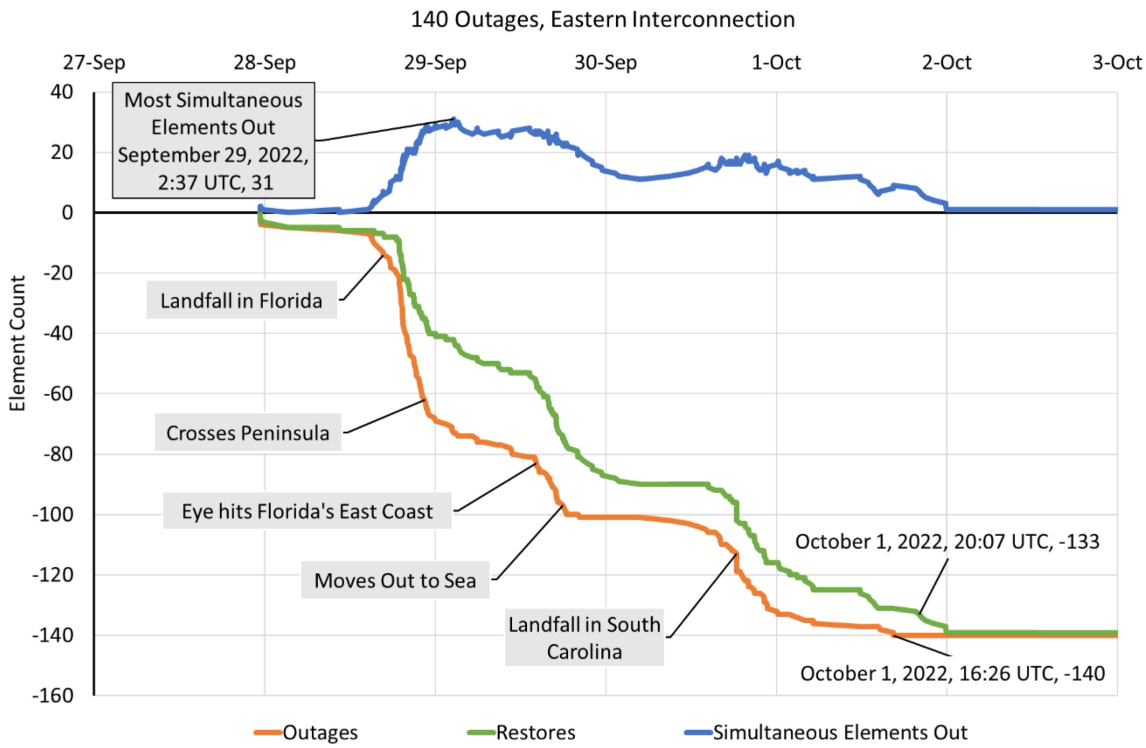


Figure 2.6: Transmission Element Outage, Restore, and Performance Curves for Hurricane Ian (Truncated at the 95% restoration level)

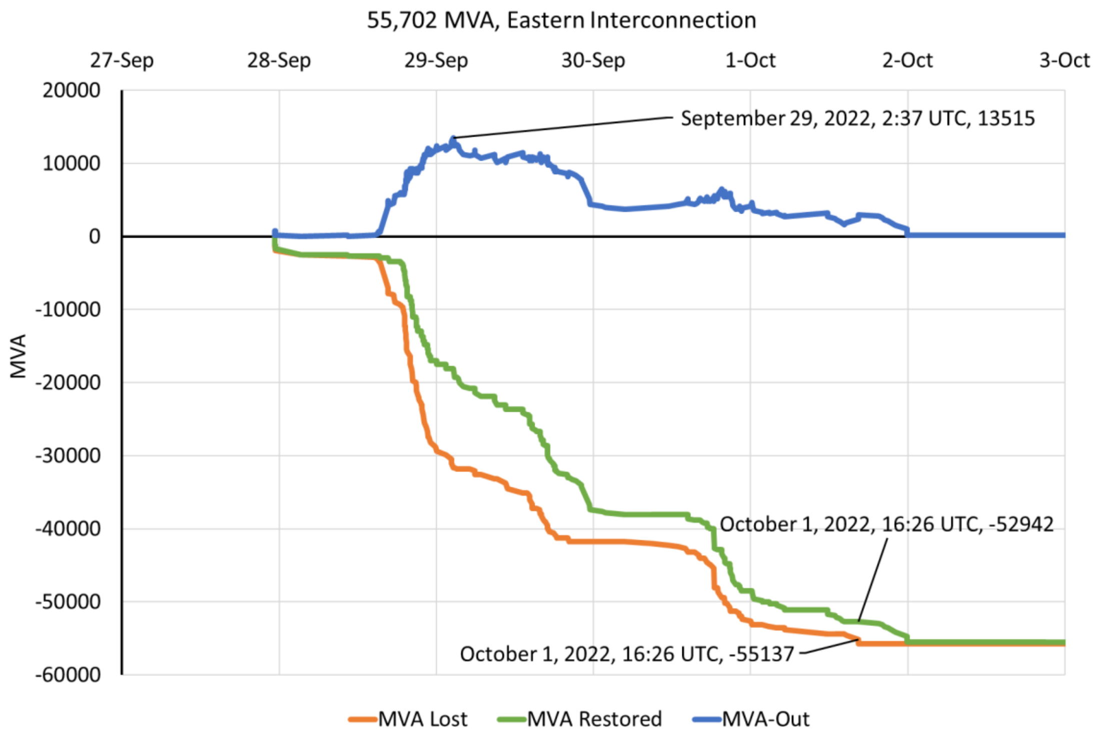
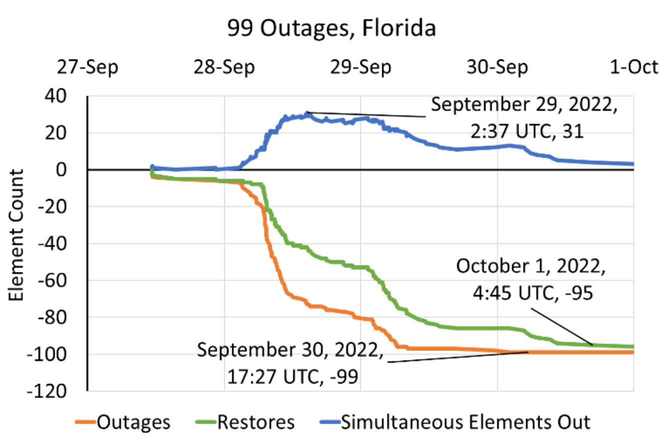


Figure 2.7: Transmission Capacity (MVA-based) Outage, Restore, and Performance Curves for Hurricane Ian (Truncated at the 95% restoration level)

The restoration process for the Florida event, **Figure 2.8**, was relatively short for a hurricane. It was only 3.8 days versus the 12.9 days for the East Coast event in **Figure 2.9**. Florida also took the brunt of the storm, experiencing 99 outages and a maximum number of 31 elements out and 13,515 MVA capacity out in comparison to the East Coast's 41 outages and a maximum number of 13 elements out and 4,491 MVA capacity. While Florida was in its most degraded state for five minutes, the East Coast nadir occurred in the middle of a large group of momentary outages, so the time at its most degraded state was less than a minute.

Florida's restoration progressed steadily to recover 95 (95%) of the elements and 39,745 (95%) of MVA capacity affected by the hurricane after 2.93 days while the East Coast recovered 39 (95%) elements and 13,901 (95%) MVA capacity after 2.3 days. The total event losses calculated for performance curves were 44.1 element-days and 17,281 MVA capacity-days for Florida and 9.8 element-days and 4,720 MVA capacity-days for the East Coast.



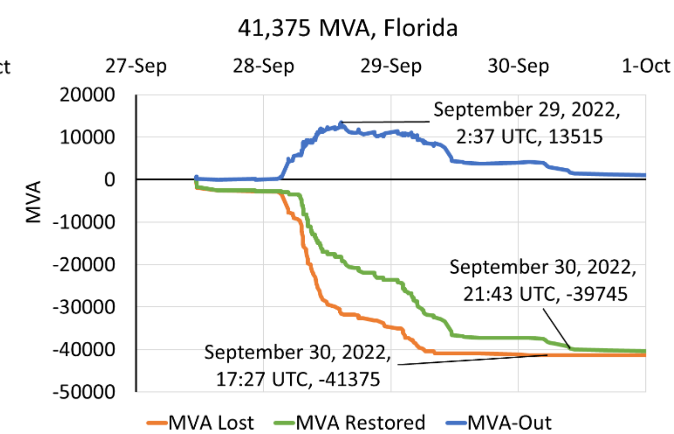


Figure 2.8: Transmission Element and MVA Capacity-based Outage, Restore, and Performance Curves for Hurricane Ian (Florida)

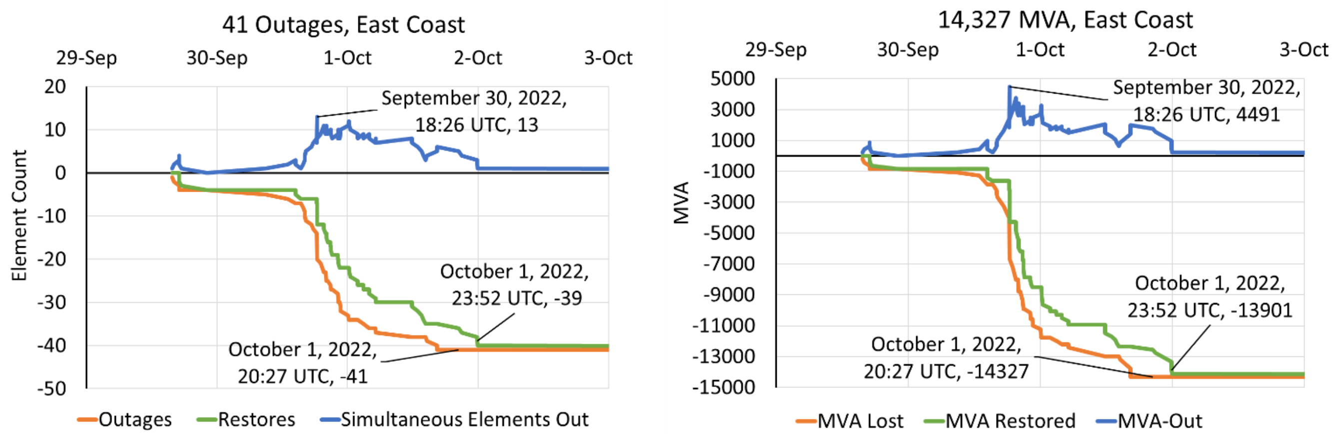


Figure 2.9: Transmission Element and MVA Capacity-based Outage, Restore, and Performance Curves for Hurricane Ian (East Coast)

The comparison of the transmission restoration from Hurricane Ian in Florida with counts of the Florida customers out provided by Eagle I leads to several observations.[38] The maximum number of customers out, 2.5 million (23.2% of Florida customers), was registered on September 29 at 10:00 p.m., more than 19 hours after the transmission system left its most degraded state (31 elements out) and was already in a fast recovery. When the recovery reached the substantial restoration level (5% or 4 elements out), there were more than 1.3 million customers out (12.1% of Florida customers). When transmission restoration for Ian was competed (on October 1 at 10:07 p.m.), there were still more than 1 million customers out (9.8% of Florida customers), and this number slowly reduced to 345,000 (3.2% of Florida customers) by October 10 at 3:45 a.m., the last data point provided in Eagle I for Hurricane Ian.

The relationship between restoration of the transmission system and the restoration of service to customers following Hurricane Ian illustrates a pattern that is typical of many severe weather events. This pattern (i.e., restoration of the transmission system prior to restoration of service to all customers) reflects the reality that damage to distribution systems can be more extensive than damage to the transmission system. It also reflects the precedence that is accorded to restoration of the transmission system because restoration of at least a portion of the transmission system is generally a prerequisite to re-energization of the distribution system in order to begin serving customer loads again.

Transmission System Resilience Statistics by Extreme Weather Type: 2017–2022

Extreme Weather Types

The outage grouping procedure identified 73 large transmission events in the years 2017–2022, and only one was not weather-related (the latter was caused by incorrect field modification and RAS operation that led to partial system collapse in 2017).[39] The 72 large weather-related events were caused by the extreme weather types listed in Figure 2.10. If several weather factors were observed together (e.g., hurricane and wind, tornado and wind), the dominant cause of the transmission outage was determined to be the extreme weather type. Multiple sources were used to determine an extreme weather event associated with each large transmission event (e.g., NERC's daily BPS awareness reports, Velocity Suite, weather sources like NOAA and Ventusky, public media reports).

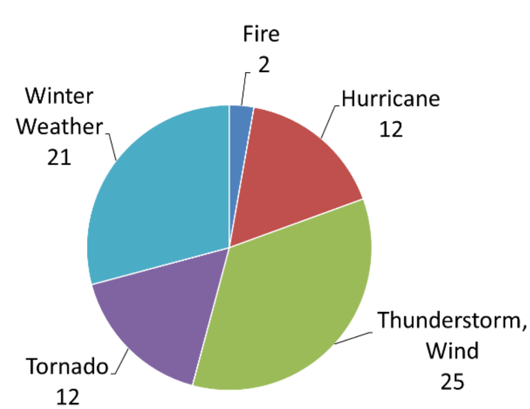


Figure 2.10: Extreme Weather Types

[38]Eagle I does not distinguish between customers affected by transmission system outages or distribution system outages. NERC monitors the impact of transmission outages on the BPS, not localized distribution system outages.

[39] LL20181002_Incorrect_Field_Modification_and_RAS_Operation_Lead_to_Partial_System_Collapse.pdf (nerc.com)

Figure 2.11 shows selected resilience statistics for the 2017–2022 events by extreme weather type. Hurricanes caused the largest transmission events with an average size of 143 outages while other groups had similar average sizes that ranged from 36–46 outages. The maximum number of elements simultaneously out (the most degraded state in an event as indicated by the nadir of the performance curve) is determined by both outage rate and restore rate, equaling 60% of the event size on average. Note that this ratio averages at 47% for the 2022 events, indicating faster or earlier transmission restoration.

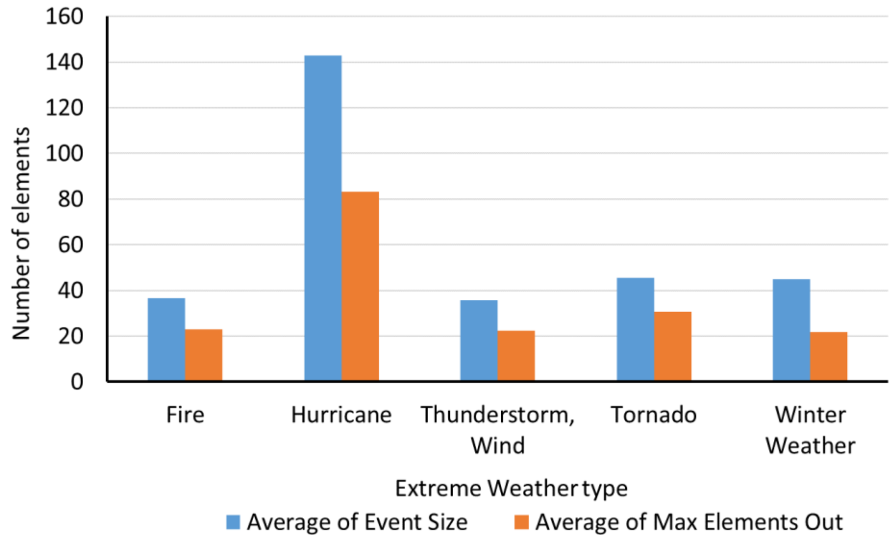


Figure 2.11: Resilience Statistics for 2017–2022 Large Weather-Related Events

Figure 2.12 compares the average event duration with the average substantial restoration duration (the times to restore 95% of outages and 95% of MVA capacity) and shows the time to first restore. One of two fire events (the 2020 WECC wildfires) had a duration of 87 days and strongly affected the average duration for the group. For other groups, the event duration is positively correlated with the event size. For all weather types, the time to restore 95% of outages is much shorter than the total event duration (on average, from 44% of the event duration for hurricanes to 60% of the event duration for tornado). The percent of an event's duration time ranges from 36% for hurricanes to 69% for tornados to reach a restoration level of 95% MVA. The first restore is typically inside one hour from the event start; hurricane events have the shortest average time to the first restore (36 minutes) among all groups (except two fire events), this indicates good advanced preparation by utilities for these forecasted events.

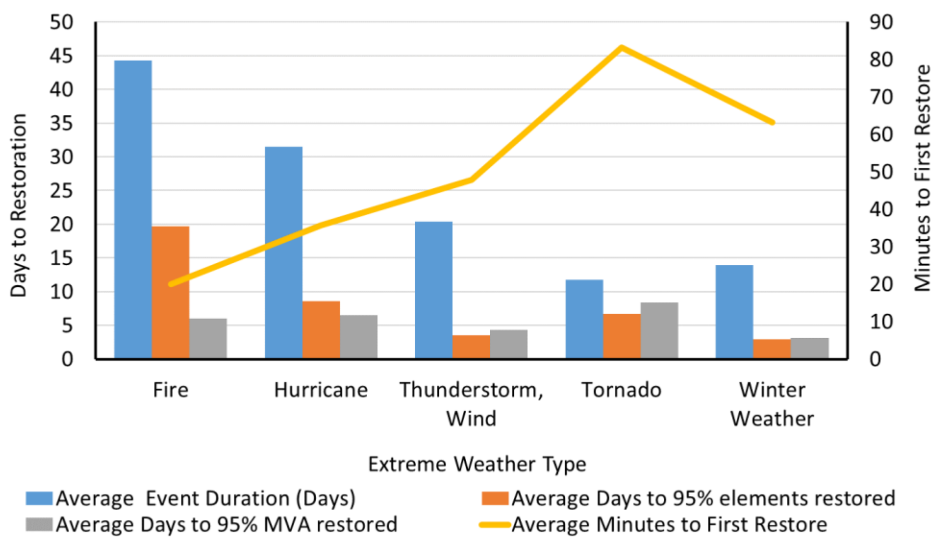


Figure 2.12: Average Event Duration vs. the Average Sustained Restoration Duration

Event duration is a straightforward metric but is too highly variable to be a reliable estimate. Moreover, it depends strongly on the last few restores, making the event duration relate poorly to transmission performance because these last restores may be unimportant for customers or may be excessively delayed by factors out of the utility's control, such as the difficulty of repairing transmission lines in the mountains in the winter or structural damage caused by hurricane or tornado.[40] The substantial restoration duration is a preferable metric to measure and track the ability of transmission system to recover from outage events caused by extreme weather.

Changes in Resilience Statistics: 2018–2022 Events vs. 2017–2021 Events

To draw conclusions about improving, stable, or declining transmission resilience against extreme weather, the analysis focuses on capturing changes in the several metrics that quantify resilience over years. The resilience statistics are calculated for large weather-related events for the years 2017–2021 and for the years 2018–2022, and changes in the metrics by extreme weather types were analyzed. The five-year time period is selected due to a small annual number of events in some groups (e.g., Fire).

The bubble charts in **Figure 2.13** and **Figure 2.14** show the groups of large weather-related transmission events by extreme weather type; five bubbles in **Figure 2.13** correspond to the groups for combined 2017–2021 data, and five bubbles in **Figure 2.14** show the same groups for combined 2018–2022 data. The size of a bubble represents the group size. The X-axis of a bubble center shows the average time to restore 95% of outages for the events in this group; the Y-axis shows the average number of outages for the events. The bubble color indicates the average MVA-day loss for each group: below 30,000 MVA days is shown in **blue**, between 30,000 and 100,000 MVA days is shown in **yellow**, and above 100,000 MVA days is shown in **orange**.

Change in size or position of a bubble for the same extreme weather type from **Figure 2.13** to **Figure 2.14** indicates changes in the impact of that weather resulting from a combination of the weather frequency and severity and improved or declined resilience performance. There was an increase in the number of events and the number of outages in them for the Winter Weather group driven by five 2022 Winter Weather events (see **Table 2.6**). There was an observable change in the position of the Hurricane group caused by a decrease in both the average event size due to removal from the group Hurricane Irma (2017) that was the largest transmission event in 2017–2022. A bubble for the Tornado group moved to the left indicating an improved recovery to substantial restoration level of 95% of MVA—from 169 hours to 153 hours on average. The tornado events still have the second largest average MVA-days loss after the hurricane events.

[40] I. Dobson, S. Ekisheva, How long is a resilience event in a transmission system?: Metrics and models driven by utility data (arxiv.org).

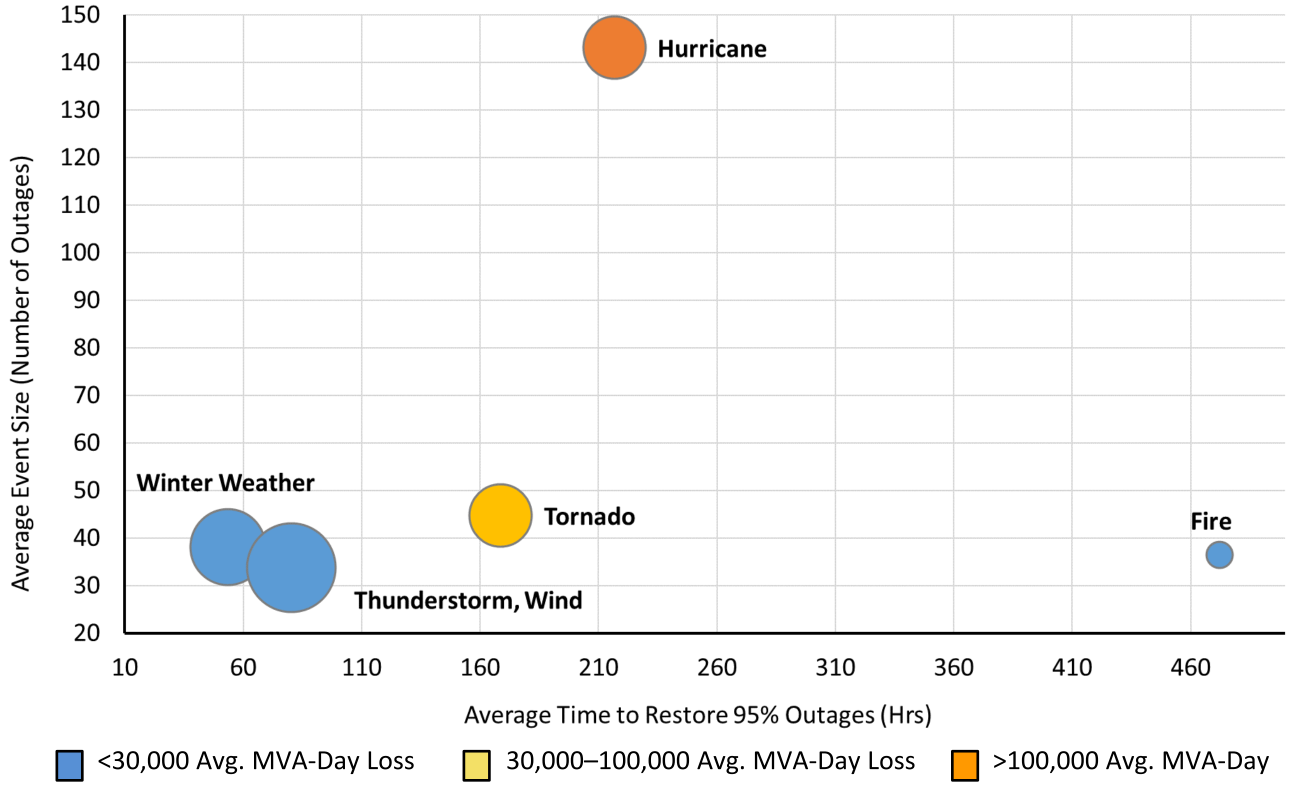


Figure 2.13: Statistics for Large Transmission Events by Weather Type for 2017–2021

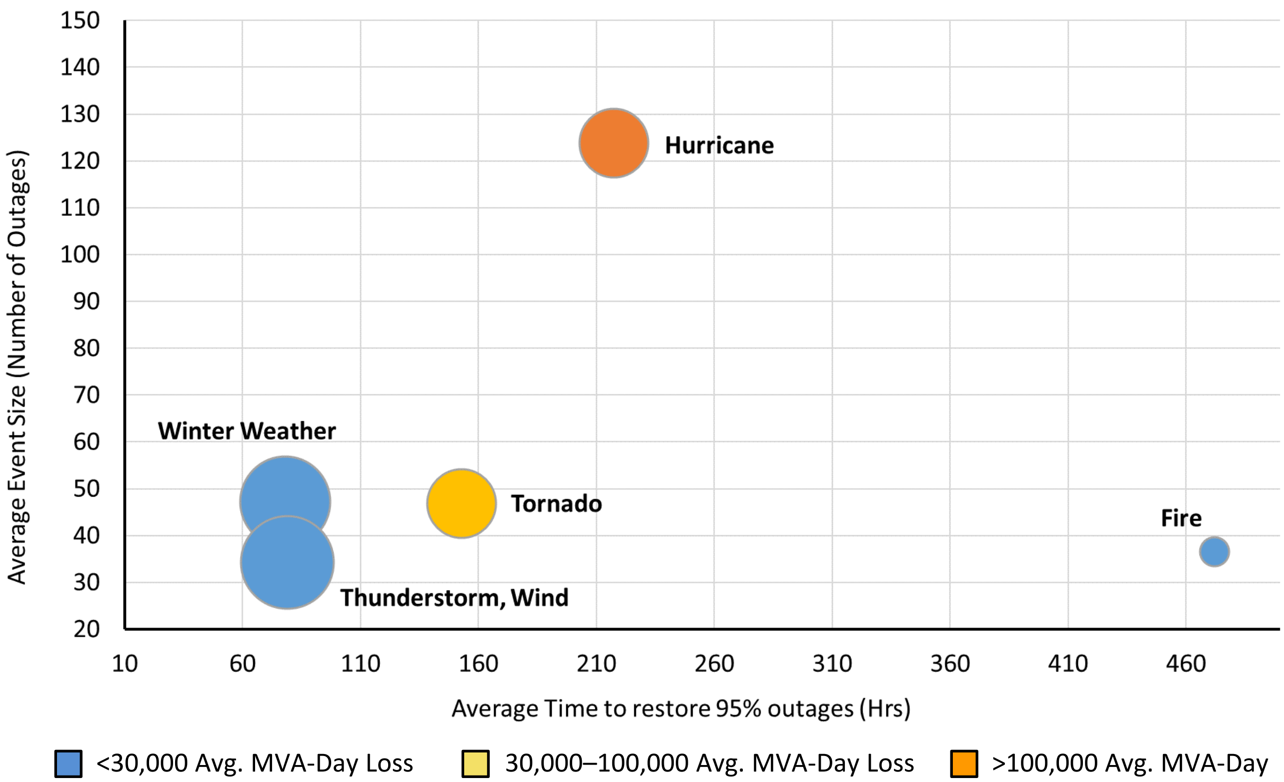


Figure 2.14: Statistics for Large Transmission Events by Weather Type for 2018–2022

Resilience Analysis Observations and Conclusions

NERC staff used the outage and restore processes for the large weather-related transmission events to define several resilience statistics that measure and track the system's ability to absorb or withstand, adapt or protect, and recover and reduce the extent and duration of extreme weather events. Several conclusions and observations from this analysis are listed as follows:

- All large events identified from the 2017–2022 TADS data except one[41] were weather-related. This confirms that extreme weather is the major risk to resilience of the transmission BPS.
- Hurricanes cause the largest, longest, and most impactful events on the transmission system (as measured by element and MVA-days loss). In 2022, Hurricane Ian was the largest event in both the number of outages and MVA affected.
- Hurricane Ian resulted in a relatively quick restoration that started just one minute from the event start and progressing steadily to recover 95% of the elements and MVA after 3.84 days (or 26% of the total event duration).
- Typically, the most degraded state during a large transmission event (the maximum simultaneous number of elements and MVA out) occurs relatively soon after the event start, and the system remains in this state for only a few minutes.
- The restore process starts quickly after the event start (usually during the first hour), progresses quickly, and then slows down. Often a single (or few) elements remain unrestored for many days or sometimes weeks.
- The 95% restoration level is reached much faster relative to the event duration. On average, it takes about 53% of the event duration to restore 95% of outages and 51% of event duration to restore 95% of MVA.
- From 2017–2021 to 2018–2022, the average size of hurricane events decreased. The average size, the number of winter weather events, and their substantial restoration time increased (due to the 2022 winter events). The time to substantial restoration decreased for the Tornado group.
- Compared with the previous five years, the time to substantial restoration in 2022 and the average relative value of the most degraded state decreased likely indicating an improving trend in transmission restoration. Additional years of the outage data as well as incorporation in the analysis more detailed weather data are needed for more reliable inferences.

[41] LL20181002_Incorrect_Field_Modification_and_RAS_Operation_Lead_to_Partial_System_Collapse.pdf (nerc.com)

Resource Adequacy

For this report, two measures of resource adequacy are examined for the BES: Planning Reserve Margin and Energy Emergency Alerts. Planning Reserve Margins present a forward-looking perspective on whether sufficient resources are expected to be available to meet demand. The EEAs provide a real-time indication of potential and actual energy emergencies within an Interconnection.

Planning Reserve Margin

Planning Reserve Margins are a long-term resource adequacy indicator, which is defined as the difference in resources (anticipated or prospective[42]) and net internal demand then divided by net internal demand and shown as a percentage.

The Planning Reserve Margins (Anticipated Reserve Margin or Prospective Reserve Margin) are compared against the Reference Margin Level (RML) to measure resource adequacy for the planning period. Figure 3.1 shows the 2022 summer peak Planning Reserve Margin by assessment area, and Figure 3.2 shows the 2022–2023 winter peak Planning Reserve Margin by assessment area.

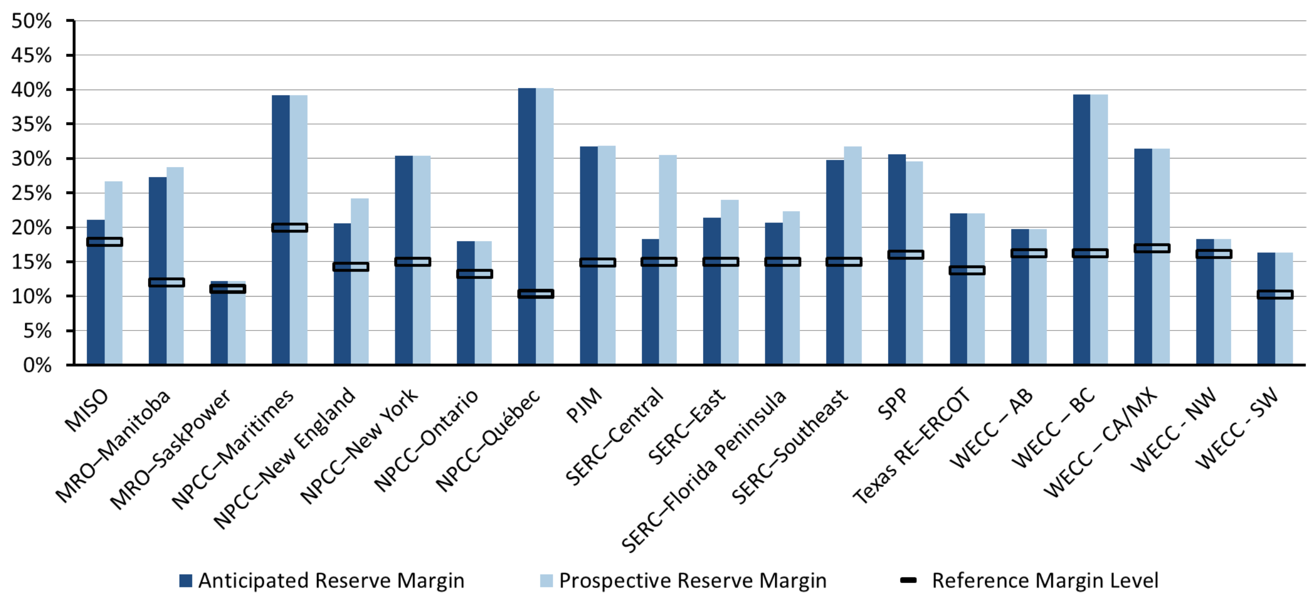


Figure 3.1: 2022 Summer Peak Planning Reserve Margins (Anticipated and Prospective Reserve Margins)

[42] Anticipated and prospective resources and all reserve margins are defined in detail on pages 102–104 in the ***2022 Long-Term Reliability Assessment***.

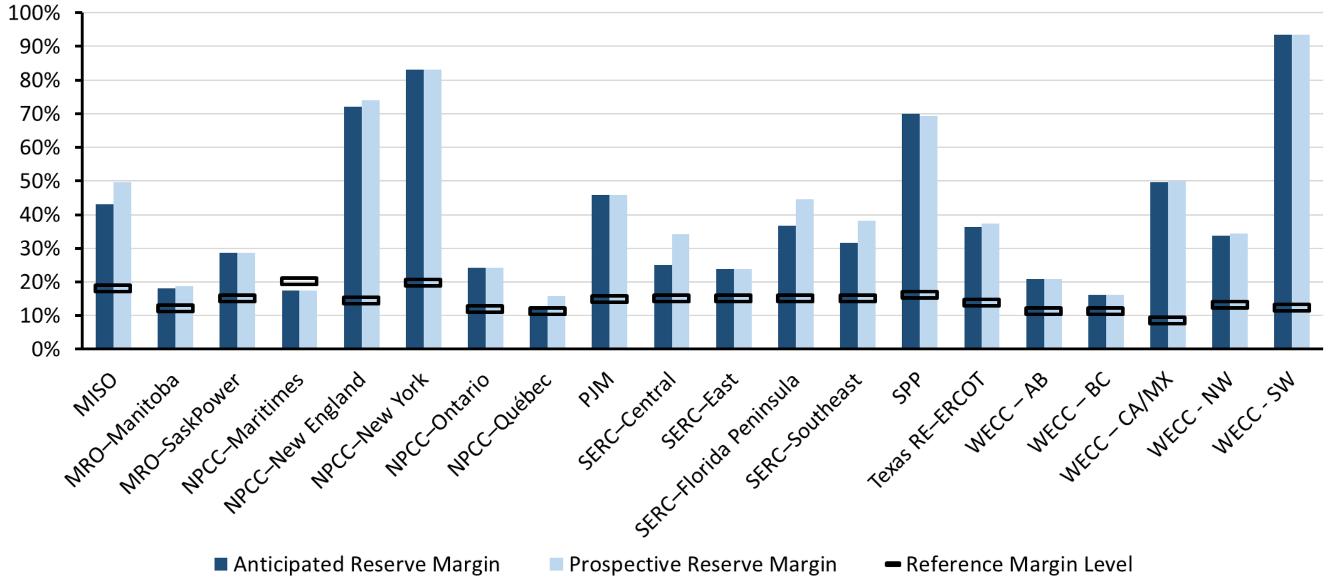


Figure 3.2: Winter Peak Planning Reserve Margins (Anticipated and Prospective Reserve Margins) 2022–2023

2022 Performance and Trends

The Planning Reserve Margins exceeded the RML for all assessment areas ahead of the Summer 2022 period. For the Winter 2022–2023 period, Planning Reserve Margins exceeded RMLs for all assessment areas except NPCC-Maritimes (see **Figure 3.1** and **Figure 3.2**). Winter peak electricity demand was projected to grow in NPCC-Maritimes, raising concerns that supply capacity could be strained to meet normal winter peak conditions. The risk of electricity shortfall in NPCC-Maritimes was moderated by the reliable generator performance of the area's winterized generation fleet.

Anticipated Reserve Margins and RMLs are not the only indicators used by the ERO to assess the risk of supply shortfall. The expected impact of generator outages and extreme operating conditions on electricity supply and demand are also considered in NERC's seasonal reliability assessments. Increased demand caused by extreme temperatures and higher than anticipated generator forced outages, and derates can create conditions that lead system operators to take emergency operating actions. The maps in **Figure 3.3** and **Figure 3.4** highlight the assessment areas that were identified ahead of the Summer 2022[43] and the Winter 2022–2023[44] seasons as at risk for resource deficiencies based on the information in **Table 3.1** and **Table 3.2**.

Note: The information in **Table 3.1** and **Table 3.2** represents forward-looking projections from the 2022 summer and 2022–2023 winter. Some risk descriptions evaluate extreme operational scenarios that are mitigated in real-time. Further details regarding these past projections can be found in the *2022 Summer Reliability Assessment* and the *2022–2023 Winter Reliability Assessment*.

[43] NERC 2022 Summer Reliability Assessment
[44] NERC 2022/2023 Winter Reliability Assessment

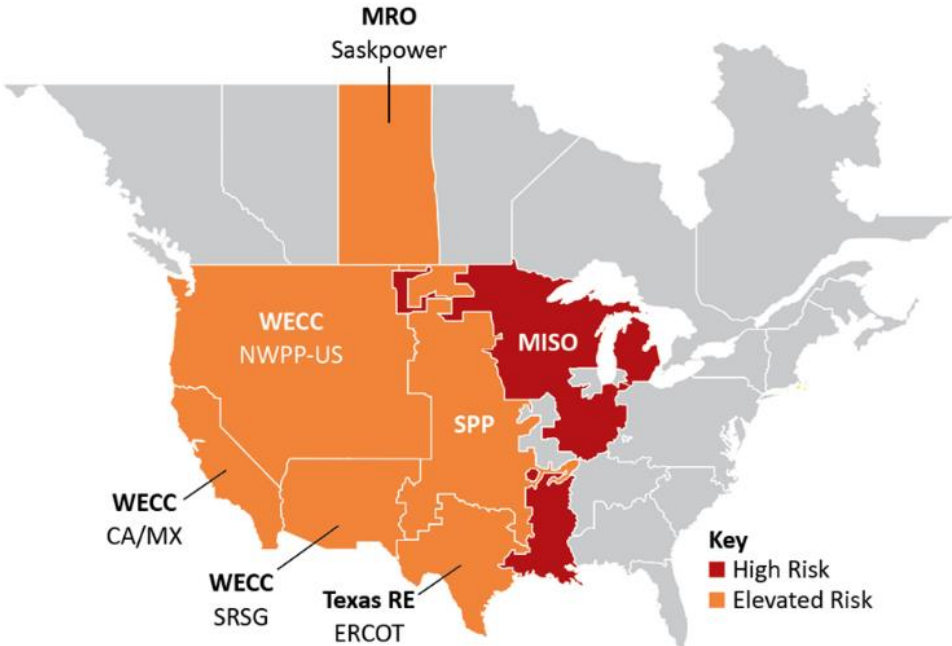


Figure 3.3: 2022 Summer Reliability Assessment Risk Area Map

Table 3.1: 2022 Summer Reliability Assessment Risk Areas

Assessment Area	Risk Category	Risk Description
MISO	High	A capacity shortfall was projected in normal (50/50) peak demand conditions due to 3,200 MW of reduced generating capacity and increased peak demand.
MRO-SaskPower	Elevated	Extreme conditions could result in the need for external assistance as projected normal (50/50) peak demand increased 7.5% since Summer 2021.
SPP	Elevated	Drought conditions affecting the Missouri River Basin caused concerns of reduced thermal generator availability due to lack of cooling water supply.
Texas RE-ERCOT	Elevated	Extreme drought across Texas led to concerns of weather conditions that were favorable to prolonged, wide-area heat events and extreme peak electricity demand.
WECC-CA/MX	Elevated	Reduced energy output from hydro generators in the Western United States led to concerns of reduced electricity transfer into WECC-CA/MX during hot summer evenings with high demand and reduced wind and solar PV output.
WECC-NWPP-US	Elevated	Reduced energy output from hydro generators in the Western United States
WECC-SRSG	Elevated	Reduced energy output from hydro generators in the Western United States led to concerns of reduced electricity transfers into WECC-SRSG

Risk Categories

High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

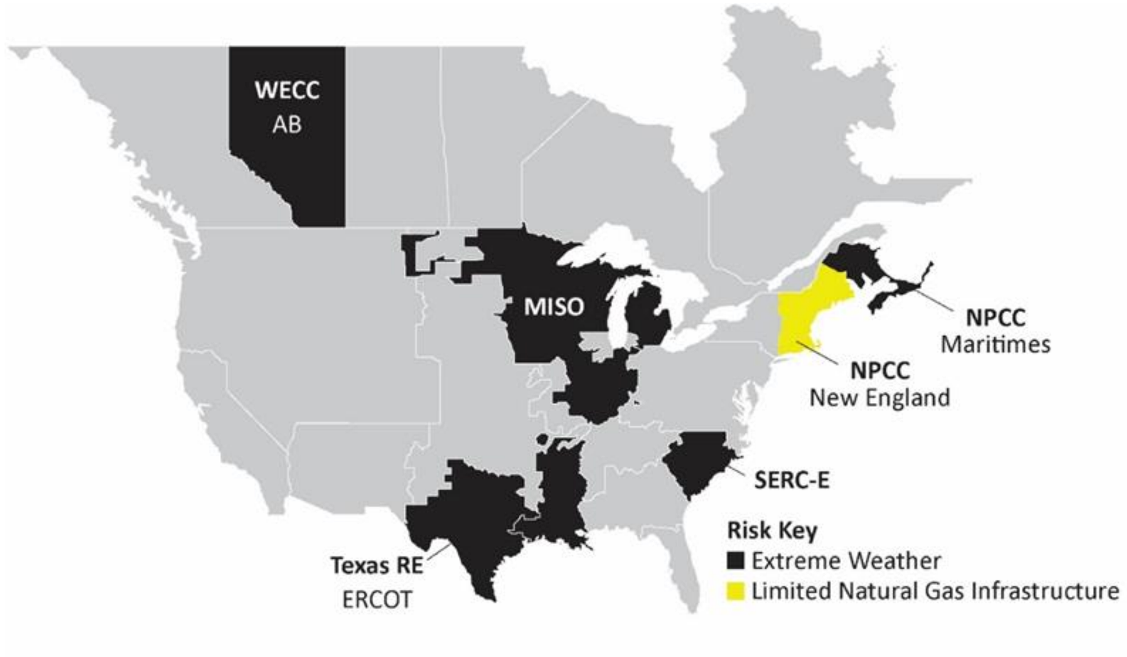


Figure 3.4: 2022–2023 Winter Reliability Assessment Risk Area Map

Table 3.2: 2022—2023 Winter Reliability Assessment Risk Areas

Assessment Area	Risk Category	Risk Description
MISO	Extreme Weather	Nuclear and coal-fired generation retirements and few capacity additions reduced reserves in MISO with a risk of high generator forced outages and demand volatility in an extreme cold weather event
NPCC-Maritimes	Extreme Weather	Peak electricity demand growth led to reduced reserves, but low outages anticipated in a cold weather event due to winterized generation fleet.
NPCC-New England	Limited Natural Gas Infrastructure	The capacity of the natural gas transportation infrastructure could be constrained when cold temperatures cause peak demand for both electricity generation and consumer space-heating needs
SERC-E	Extreme Weather	Risk of high generator forced outages and demand volatility in an extreme cold weather event
Texas RE-ERCOT	Extreme Weather	Risk of significant forced outages of non-weatherized generators and fuel supply infrastructure in extreme and prolonged cold weather
WECC-AB	Extreme Weather	Peak electricity demand growth led to reduced reserves with an increased risk of high generator forced outages in extreme weather conditions.

2022 Capacity and Energy Performance

Actual operating conditions in 2022 stressed energy supplies to meet demand. NERC's seasonal assessments identified risks of supply shortfalls that were realized during peak summer and winter conditions. In 2022, there were 21 EEA-3s issued that were the result of operator-projected reserve deficiencies from insufficient electricity supplies to meet forecasted demand. These EEAs provide an indication of resource and energy adequacy issues experienced by system operators during the year. This count of EEAs exclude events that were the result of transmission outages or storm damage to transmission. **Table 3.3** provides an overview of resource and energy adequacy EEAs. Additional reporting and analysis of EEAs is found in the **Energy Emergency Alerts** section.

Table 3.3: 2022 Resource and Energy EEA-3 Summary			
Date (2022)	Region	EEA Description	NERC Seasonal Assessment Indication
January 12	SERC	A forced generator outage during early morning triggered a BA to declare an energy emergency due to reserve deficiency. Shortage addressed through transfer from neighboring BA area. No load loss.	The assessment area had sufficient resources to meet load as expected.
August 31–September 10	WECC	September Heat Dome led to seven EEAs in Canadian, U.S., and Mexican parts of the Western Interconnection. Record demand, transfer curtailments, generator energy output, and generator availability contributed to reserve shortages.	Each assessment area where EEAs occurred was assessed as having elevated risk for supply shortfalls in a wide-area heat event
December 1–2	WECC	A BA in Canada declared an energy emergency during extreme cold temperatures due to expected reserve deficiency	The assessment area was assessed as having risk of supply shortfalls in extreme conditions.
December 21–26	WECC, SERC	Winter Storm Elliott led to 12 EEA-3s from Western Canada to the U.S. Mid-South and Southeast. Record demand, generator outages, and fuel availability contributed to reserve shortages.	Each assessment area where EEAs occurred was assessed as having risk for supply shortfalls in extreme weather with the exception of SERC-Central. Further analysis of this event is underway by a joint FERC-NERC inquiry team.

Changes in the Peak Resource Mix over the Past 10 Years

Over the past 10 years, the BPS has reduced its on-peak capacity of coal by 106.2 GW. During this time, the BPS added 68 GW of natural gas, 14.2 GW of wind, and 40.6 GW of solar PV generation on-peak capacity.[45] As the BPS generating resource mix continues to rapidly transition from coal-fired to natural gas, solar PV, and wind, the operating characteristics of the incoming resources require careful planning. VERs, such as wind and solar PV, contribute to resource adequacy; because their output depends on the environment and local weather conditions, they often do not provide the same contribution to capacity at the peak demand hour (i.e., on-peak) as their nameplate (or installed) capacity. **Table 3.4** shows the changing on-peak capacity composition of generating resources in North America over the past 10 years. The installed nameplate capacity for wind and solar PV resources has grown considerably over the past decade: wind installed capacity has grown from 55.8 GW to 148.5 GW, and solar PV has risen from just under 3.1 GW to over 56.3 GW in the 10-year period. However, wind and solar PV resource contribution to meeting demand on-peak has changed modestly, rising from 2% to 7% of on-peak capacity during the 10-year period.

Table 3.4: Generation Resource Capacity by Fuel Type				
Generation Fuel Type	2012 On-Peak		2022 On-Peak	
	GW	Percent	GW	Percent
Coal	317.0	28.7%	201.8	19.1%
Natural Gas	411.4	37.3%	479.4	45.4%
Hydro	155.6	14.1%	137.3	13.0%
Nuclear	133.4	12.1%	106.2	10.1%
Oil	54.2	4.9%	34.1	3.2%

[45] Data obtained from Energy Information Administration and NERC long-term reliability assessments.

Table 3.4: Generation Resource Capacity by Fuel Type

Generation Fuel Type	2012 On-Peak		2022 On-Peak	
	GW	Percent	GW	Percent
Wind	18.8	1.7%	33.0	3.1%
Solar PV	3.3	0.3%	43.9	4.2%
Other	9.3	0.8%	20.0	1.9%
Total:	1102.9	100.0%	1055.7	100.0%

The resource mix and the pace at which it is changing varies considerably across different parts of the North American BPS. Figure 3.5 provides an Interconnection-level view of the generation resource mix since 2012. NERC's LTRA reports on both the current generation resource mix and projections for the next 10 years for each of the 20 assessment areas within the four Interconnections that encompass the North American BPS.

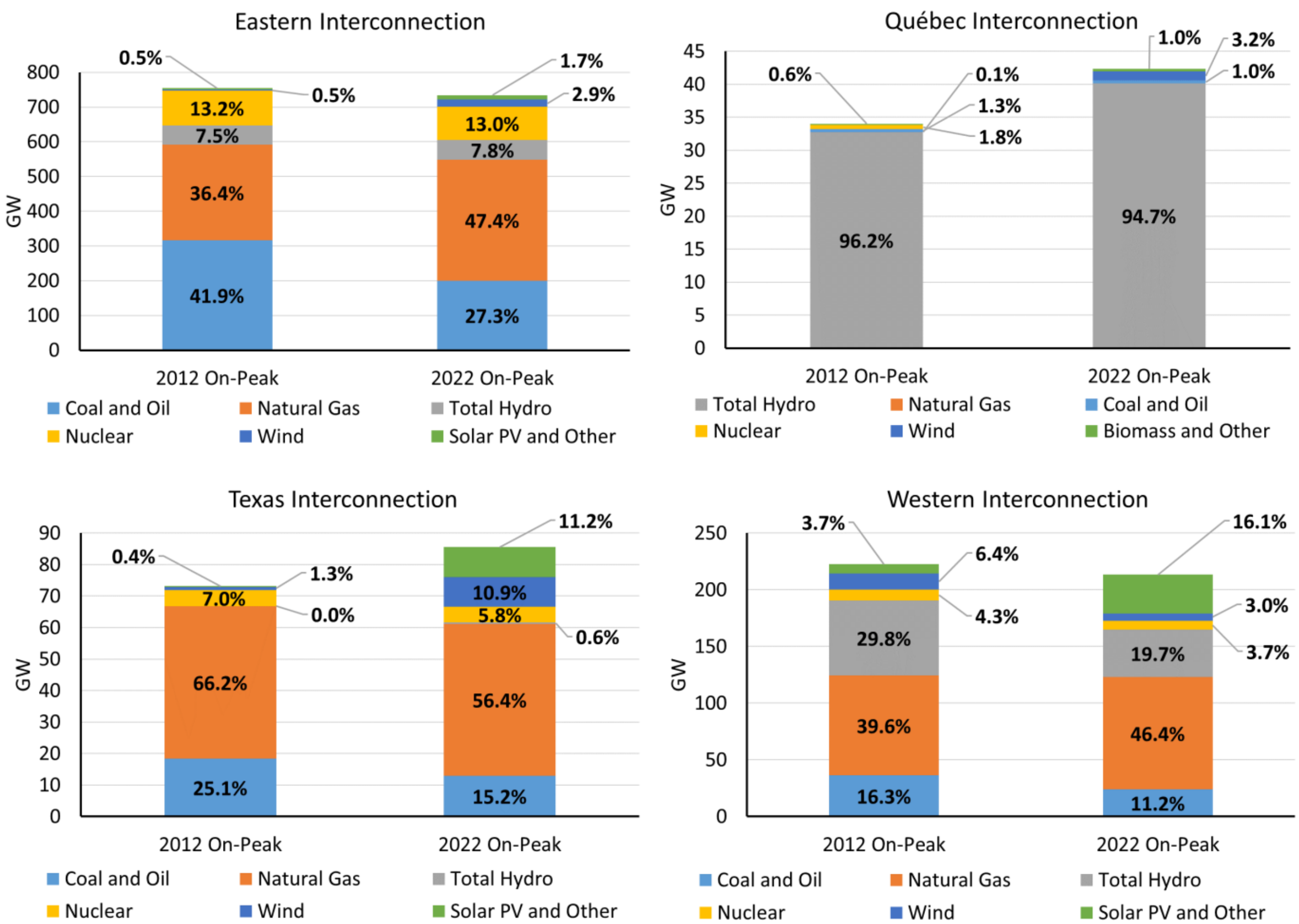


Figure 3.5: 2012 and 2022 Capacity Resource Mix by Interconnection

Managing Risks as the Resource Mix Evolves

The growth of VER and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. Planning and operating the grid must increasingly account for energy limitations and variability across the resource fleet. At the same time, many areas are seeing increasing volatility in forecasted electricity demand as variable demand-side resources grow. Energy assessments that consider variability in resources and demand across all hours of the assessment period are increasingly important to maintaining resource adequacy of the BPS.[46] Ensuring sufficient flexible resources, maintaining fuel assurance, and planning and operating the BPS with VERs are all key reliability elements for managing the changing resource mix.

Ensuring Sufficient Flexible Resources

As **Figure 3.6** shows, flexible resources are playing an increasing role in addressing net internal demand. Texas RE-ERCOT, for example, relies on solar PV and wind resources to serve 5.3% of its (peak) net internal demand.[47] Sufficient flexible resources are needed to ensure resource adequacy and energy sufficiency as the grid transforms and to reduce the exposure to energy shortfalls during times when VER output is lower than forecasted. Until storage technology is fully developed and deployed at scale, natural-gas-fired generation will remain a necessary balancing resource to meet the flexibility needs of the system.

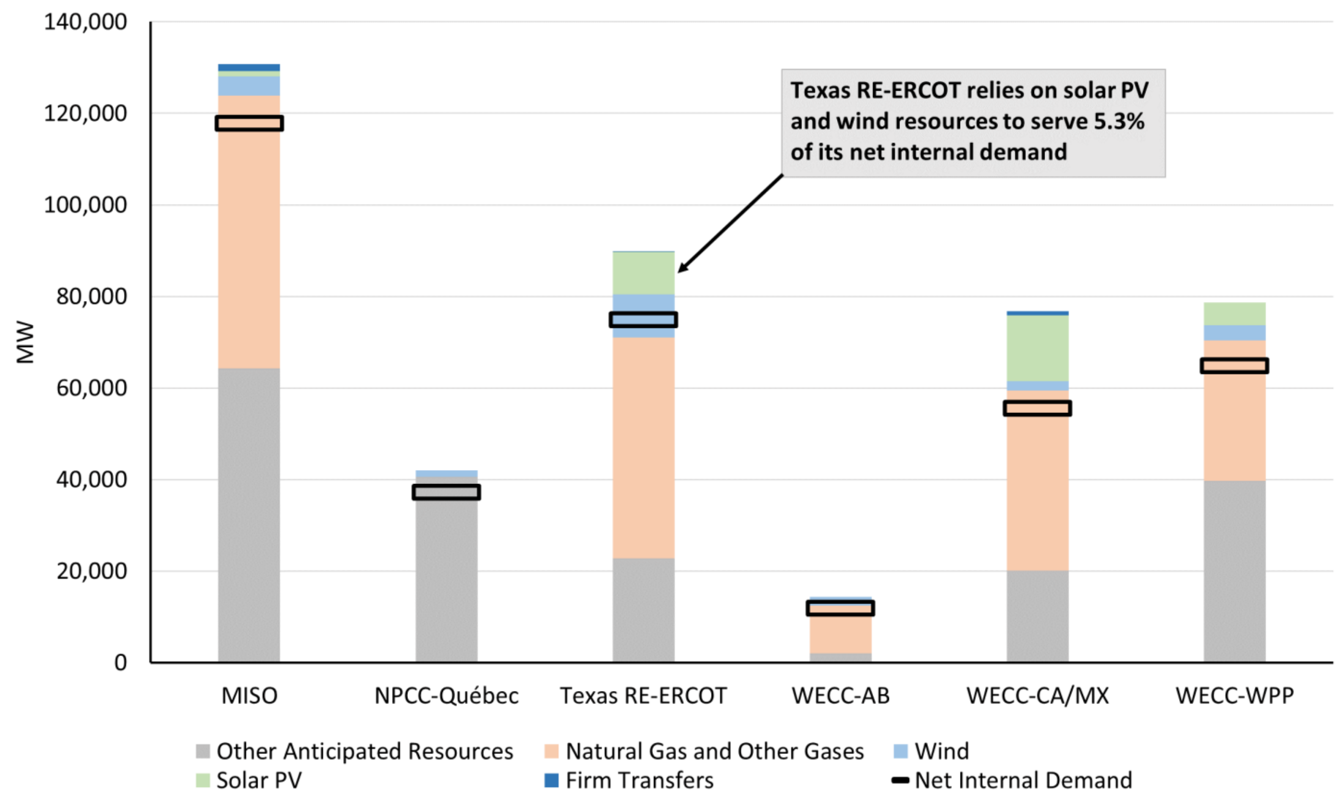


Figure 3.6: Resource Contributions to Meeting Net Internal Demand

Resource Mix Examined in Hourly Generation Data

While the growing contribution of wind and solar PV generation is noticeable in the 10-year on-peak capacity, greater contributions can be seen when examining hourly generator data over the full year. **Figure 3.7** shows monthly maximum, minimum, and average contributions of grid-connected wind and solar PV generation for some BAs from 2022 data reported to the U.S. Energy Information Administration.[48] The depictions give additional details about how the mix of generation in the BA areas was used to serve electricity demand in 2022.

[46] For more information on energy assessments, see the *2022 Long Term Reliability Assessment* and the included 2022 ERO probabilistic assessment, which accounts for all hours in selected study years of 2024 and 2026.
[47] Net internal demand is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf at p. 122.
[48] Data from U.S. Energy Information Administration, EIA-930 Hourly Electric Grid Monitor: https://www.eia.gov/electricity/gridmonitor/about

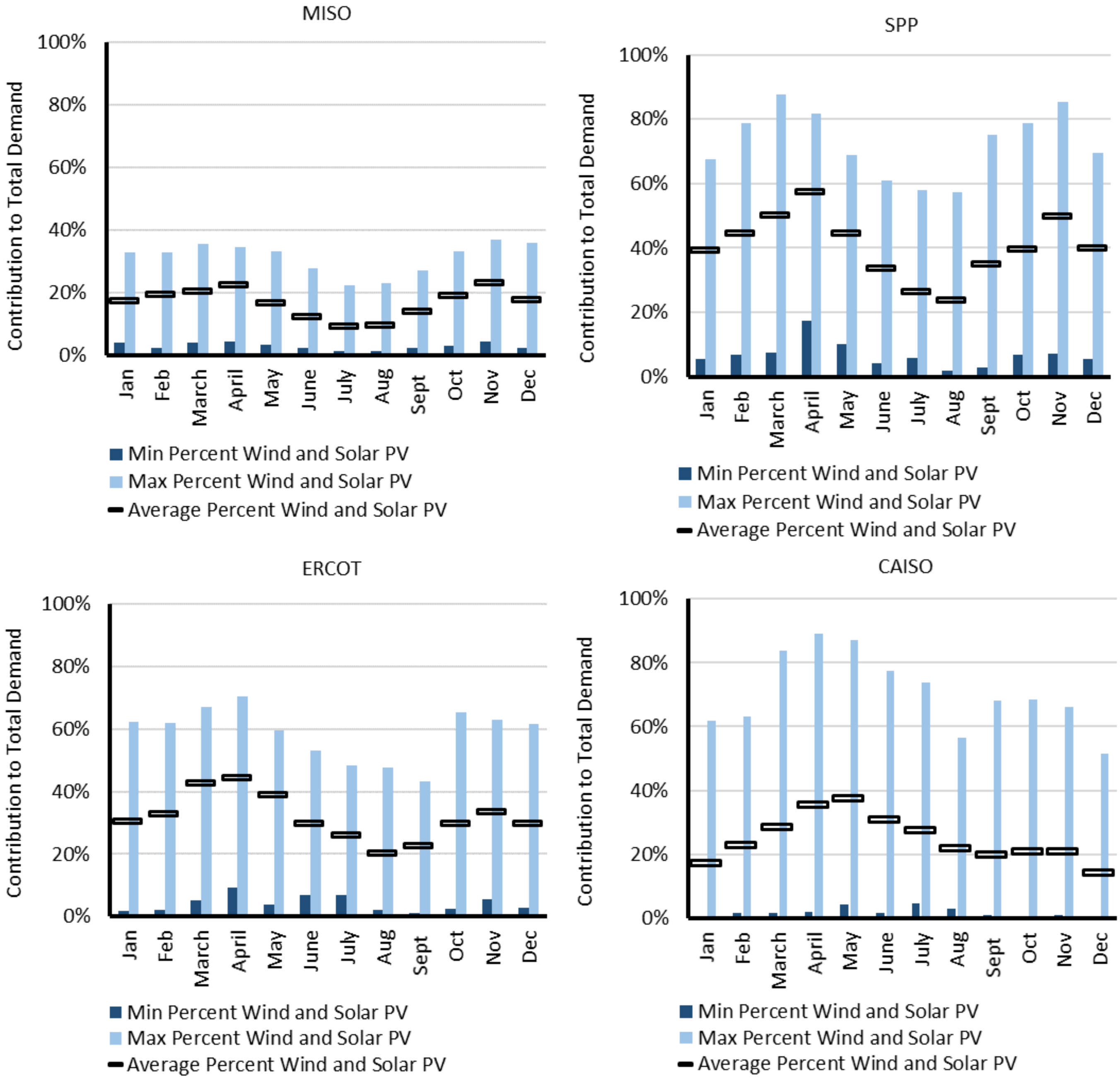


Figure 3.7: 2022 Monthly Maximum, Minimum, and Average Contributions of Grid-Connected Wind and Solar PV Generation

The growth in IBRs adds complexity to operational planning and real-time operations, which is shown in Figure 3.7 by the large difference in penetration levels between maximum percentages versus the average percentages. Seasonal, day-ahead, and real-time forecasts are used to ensure system operators have resources to balance electricity demand and supply in real-time. Sufficient dispatchable resources that can be called on by system operators in a flexible and timely manner are needed to balance changes in output from variable generation and cover forecast uncertainty.

Critical Infrastructure Interdependencies

As shown in Figure 3.8, the changing resource mix has resulted over the past decade in a BPS that is increasingly reliant upon the availability of fuels that are far less amenable to onsite storage than the fuels consumed by retired and retiring conventional coal and nuclear plants. VERs rely upon weather-dependent fuels, such as wind and solar

PV, that cannot be stored except in the case of certain solar PV generation technologies as heat for limited durations. Although storage is a critical component of the natural gas supply and transportation infrastructure, natural gas is typically delivered from pipelines to BPS generators just in time to be burned for electricity generation. Alongside these changes to the resource mix, BPS facility owners and operators have continued to enhance their operations by incorporating operational and system control and protection technologies that depend upon the availability of third-party communication facilities.

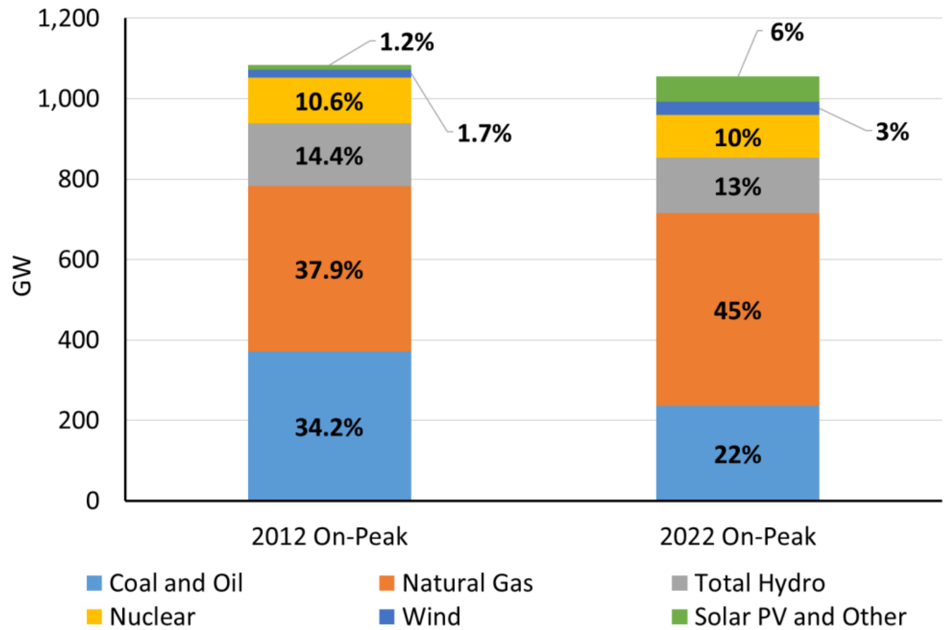


Figure 3.8: 2012 and 2022 Capacity Resource Mix across North America

The BES has never been more dependent upon the round-the-clock continuity of just in time natural gas delivery and mission-critical communications services. Additionally, NERC recognizes that the BES has similar critical dependencies on the fuel oil, water/wastewater, and even the financial sectors.[49] At the same time, the providers of these goods and services have always relied upon the BES for delivery of the electrical energy they require to supply and deliver their products. This growing symbiosis across industry sectors and energy subsectors causes critical infrastructure interdependencies that NERC has highlighted in recent years as emerging and[50] realized risks to BES reliability in the case of natural gas interdependency.

At the end of 2022, the BES was once again stressed by severe winter weather. From December 21 through December 26 an historic extratropical cyclone created winter storm conditions and record cold temperatures affecting all U.S. states from as far west as Colorado and as far south as Miami, Florida, to significant portions of Canada. The extent to which any of the aforementioned critical infrastructure interdependencies may have contributed to the Winter Storm Elliott electrical energy deficiencies is not currently known; a joint FERC-ERO inquiry into the operations of the BPS during Winter Storm Elliott is under development.

Electric-Natural Gas Interdependencies Risk

Past FERC-ERO inquiries into prior cold weather events have produced a number of recommendations specific to electric-natural gas interdependencies risk that the ERO continues to actively implement. In 2022, the ERO's Electric-Gas Working Group released a reliability guideline, *Design Basis for Natural Gas Study,*[51] to guide the performance studies of the interface between the electric and natural gas systems. Also, the ERO's Energy Reliability Assessment

[49] ERO Reliability Risk Priorities Report (Board Accepted August 12, 2021 at 32.
[50] 2022 State of Reliability, Key Finding #2
[51] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Design_Basis_for_Natural_Gas_Study.pdf

Task Force has begun drafting a white paper that describes what an energy reliability assessment is and why it is necessary[52] with a second volume to provide the necessary elements. NERC's Project 2022-03 Standard Authorization Request (SAR) Drafting Team completed two SARS to create requirements and identify functional entities for conducting energy reliability assessments in the planning and operating time horizons and developing corrective action plans to address identified risks.[53] Energy reliability assessments evaluate energy assurance across the operations planning, near-term transmission planning, and long-term transmission planning or equivalent time horizons by analyzing the expected resource mix availability (flexibility) and the expected availability of fuel during the study period. In 2022, the ERO's Real-time Operations Subcommittee updated *the Reliability Guideline: Gas and Electrical Operational Coordination Considerations*[54] to include specific metrics for evaluating natural gas system supply constraints. These constraints result in generator derates, EEA declarations, and tracking and trending the number of annual events and as the MWhs lost per event.[55]

Communications Interdependencies Risk

In April 2020, the Federal Communications Commission (FCC) issued a report and an order that partially opened the 6 GHz band of radio spectrum to unlicensed use.[56] In addition, the FCC has a pending notice of further proposed rulemaking that would fully open the 6 GHz band to unlicensed use.[57] Industry users have expressed concern that the FCC's order and the proposed rulemaking will introduce interference that is harmful to BPS operations. In December 2021, the Reliability and Security Technical Committee (RSTC) established the 6 GHz Task Force to help address that concern.

In September 2022, the RSTC approved the task force's 6 GHz *Communication Network Extent of Condition White Paper*.[58] In addition to identifying BPS reliability risks associated with 6 GHz communication interference, the white paper provides details for identifying owners and operators relying on 6 GHz to support BPS reliability and recommendations related to impact assessment to effectively manage communication disruption risks to BPS operations. As proliferation of operational technologies and consumer-use devices continues, the available spectrum becomes more constrained, and interdependencies between the communications and electric sectors become more critical.

[52] The ERATF's draft white paper was posted on March 7, 2023 for 45-day industry comment period.

[53] Project 2022-03 Energy Assurance with Energy-Constrained Resources (nerc.com)

[54] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf

[55]. The draft white paper updates were posted on November 17, 2022 for 45-day industry comment period. Those updates to the NERC Reliability Guideline were subsequently approved by the RSTC on March 22, 2023.

[56] https://www.fcc.gov/document/fcc-opens-6-ghz-band-wi-fi-and-other-unlicensed-uses-0

[57] https://www.federalregister.gov/d/2020-11320

[58] 6GHZ Communication Network Extent of Condition White Paper.pdf (nerc.com)

Energy Emergency Alerts

As shown in Figure 3.9, a total of 25 EEA-3s were declared in 2022, an increase of 15 EEA-3 declarations over 2021. Nine EEA-3 declarations included shedding of firm load. Three additional firm load shed incidents to alleviate loading on transmission lines were reported to NERC through the DOE OE-417 form in June. While the number of declarations increased from 2021, the amount of load that was shed during these events was less than 10% of the previous year (96.2 GWh versus 1,015 GWh, respectively).

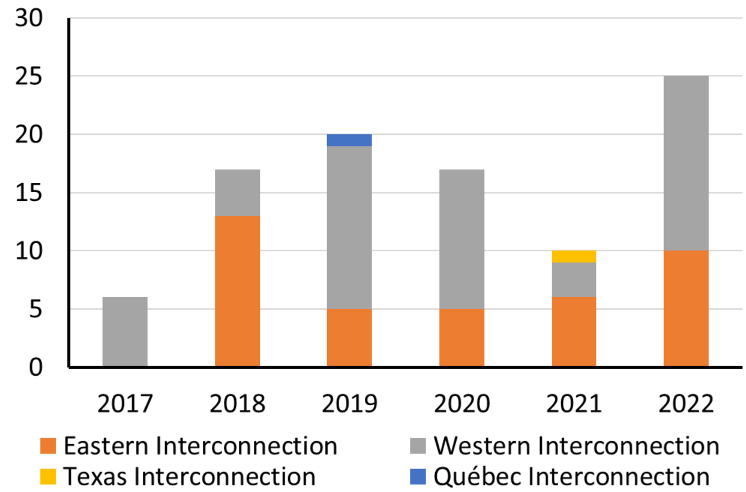


Figure 3.9: EEA-3 by Year and Interconnection

All EEA-3 declarations in 2022 were associated with periods of extreme weather. Eight of the EEA-3 reports that resulted in operator-initiated load shedding occurred during Winter Storm Elliott in December with the remaining four operator-initiated load shed incidents occurring in June. EEA-3 declarations that did not include operator-initiated load shed were related to other extreme weather impacts, including cold temperatures in January for Florida, hot temperatures in June for the Southwest, the September Western Interconnection heatwave, and the November Northwestern Arctic air-mass.

Figure 3.10 shows the number of hours when operator-initiated firm load shed was deployed during each of the past five years. In 2022, 21 hours occurred in June during excessive heat and 35.5 hours of operator-initiated firm load shed occurred during Winter Storm Elliott. The total number of hours of operator-initiated firm load in 2022, 56.5 hours, represents 0.6% of all hours in the year.

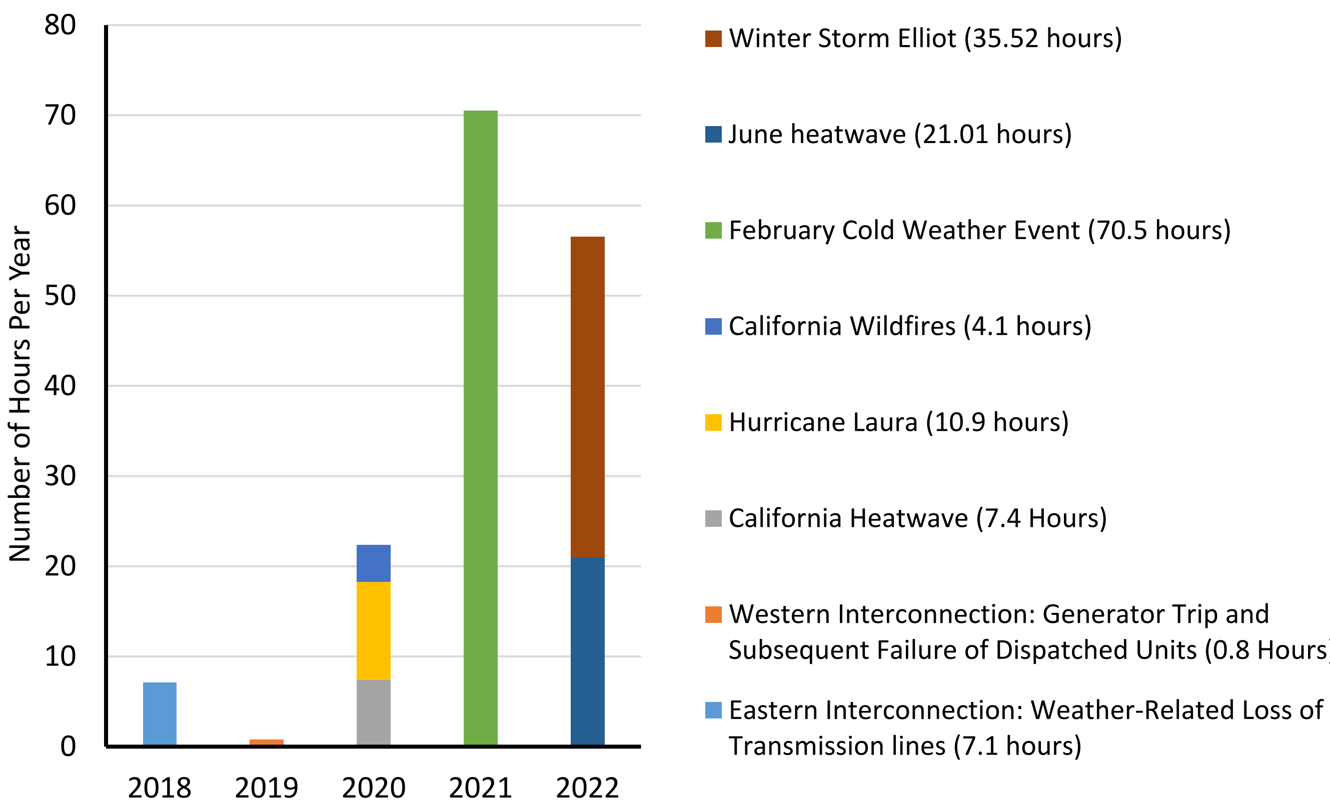


Figure 3.10: Hours with Operator-Initiated Firm Load Shed (hours/year)

Chapter 4: Grid Performance

Performance trends in terms of generation, transmission, and protection and control metrics are reviewed in this chapter. Included are the following sections:

- **System Protection and Disturbance Performance**
- **Disturbance Control Standard Metric**
- **Interconnection Reliability Operating Limit Exceedances**
- **Generation Performance and Availability**
- **Transmission Performance and Unavailability**
- **Loss of Situational Awareness**
- **Increasing Complexity of Protection and Control Systems**
- **Human Performance**
- **Cyber and Physical Security**

By calculating 2022 reliability metrics and comparing the results to the previous years as well as the five-year average values, the reliability metrics discussed in this chapter can be categorized as either Improving, Stable, Monitor, or Actionable. Measuring and trending the relative state of the BES in this manner supports the goal of encompassing NERC's responsibility to ensure the reliable planning and operation of the BES and NERC's obligation to assess the capability of the BES.

System Protection and Disturbance Performance

2022 Interconnection Frequency Response

Frequency response analysis indicates stable or improving performance for all Interconnections in both the Arresting Period and Stabilizing Period. Analysis for each of the Interconnections indicates an adequate level of reliability:

- For the Arresting Period, the Eastern Interconnection, Québec Interconnection, and Western Interconnection showed no statistically significant changes from 2018 through 2022. The TI showed a statistically significant improvement for the arresting period from 2018 through 2022.
- For the Stabilizing Period, the Québec Interconnection, Western Interconnection, and Eastern Interconnection showed no statistically significant changes from 2018 through 2022 while the TI showed a statistically significant improvement.

Of note in 2022, none of the Interconnections had events within the five-year period where the measured frequency response was less than the interconnection frequency response obligation for the respective Interconnection.

During the arresting period, the goal is to arrest the frequency decline for credible contingencies before the activation of under frequency load shedding (UFLS). The calculation for the interconnection frequency response obligation under BAL-003 is based on arresting the Point C nadir before the first step of UFLS for resource contingencies at or above the RLPC[59] for the Interconnection. Measuring and tracking the margin between the first step UFLS set point and the Point C nadir is an important indicator of risk for each Interconnection. **Figure 4.1** indicates the measurement periods used for analysis of the arresting period of events by looking at the frequency response between Value A and Point C as well as at the margin between Point C and the first step UFLS set point.

[59] BAL-003-2 specifies that the RLPC be based on the two largest potential resource losses in an Interconnection. This value is evaluated annually.

During the stabilizing period, the goal is to stabilize system frequency following a disturbance primarily due to generator governor action. **Figure 4.1** indicates the measurement periods used for analysis of the stabilizing period of events by looking at the frequency response between Value A and Value B.

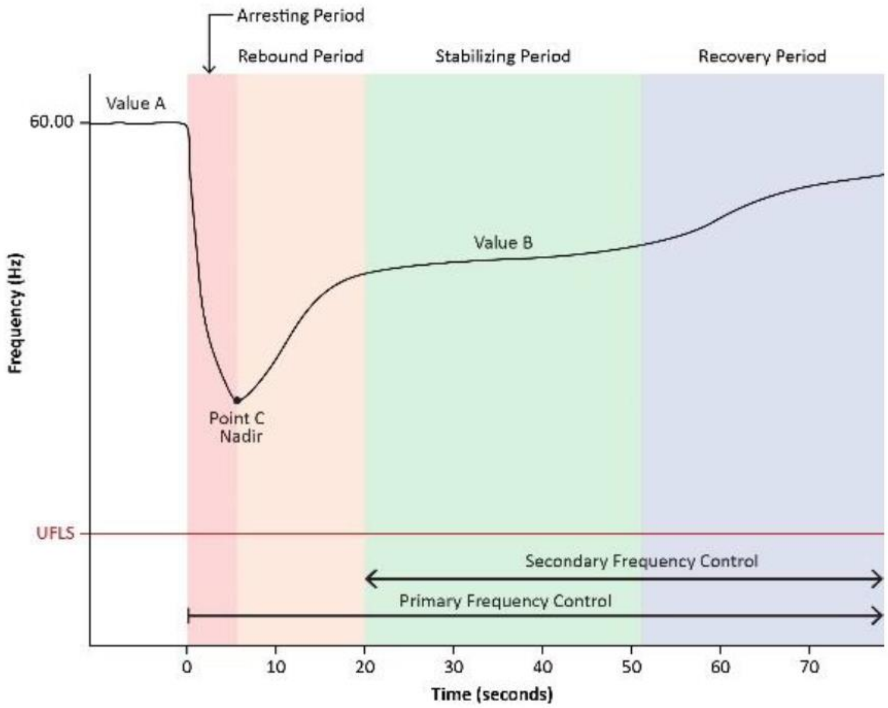


Figure 4.1: Frequency Response Methodology

Frequency response for all of the Interconnections indicates stable and improving performance for the stabilizing period and arresting period as shown in **Table 4.1** and **Table 4.2**.[60]

Table 4.1: 2022 Frequency Response Performance Statistics for Stabilizing Period

	2022 Operating Year Stabilizing Period Performance					
	Mean $IFRM_{A\text{-}B}$ (MW/0.1Hz)	Median $IFRM_{A\text{-}B}$ (MW/0.1Hz)	Lowest $IFRM_{A\text{-}B}$ (MW/0.1Hz)	Maximum $IFRM_{A\text{-}B}$ (MW/0.1Hz)	Number of Events	2018–2022 OY Trend
Eastern	2,648	2,423	1,594	5,342	46	Stable
Texas	1,287	1,163	511	2,955	32	Improving
Québec	1,009	859	512	2,331	22	Stable
Western	1,934	1,763	1,114	4,917	30	Stable

Table 4.2: 2022 Frequency Response Performance Statistics for Arresting Period

	2022 Operating Year Arresting Period Performance					
	Mean $IFRM_{A\text{-}C}$ (MW/0.1Hz)	Median $IFRM_{A\text{-}C}$ (MW/0.1Hz)	Lowest $IFRM_{A\text{-}C}$ (MW/0.1Hz)	Mean UFLS Margin (Hz)	Lowest UFLS Margin (Hz)	2018–2022 $IFRM_{A\text{-}C}$ OY Trend
Eastern	2,050	1,921	1,202	0.455	0.419	Stable
Texas	575	532	305	0.584	0.486	Improving
Québec	157	148	95	1.121	0.938	Stable
Western	886	846	535	0.413	0.330	Stable

60 Frequency Response Performance Statistics

Figure 4.2 represents an analysis of the arresting period of M-4 events. The Y-axis shows the percent UFLS margin from 100% (60 Hz) to 0% (first step UFLS set point for the Interconnection). The X-axis represents the MW loss for the event, expressed as a percentage of the RLPC for the Interconnection. The Western Interconnection and Québec Interconnection each had one event at or greater than 100% of the RLPC and maintained sufficient UFLS margin. The largest events as measured by percentage of RLPC for the Eastern Interconnection and Texas Interconnection were 45% and 50%, respectively.

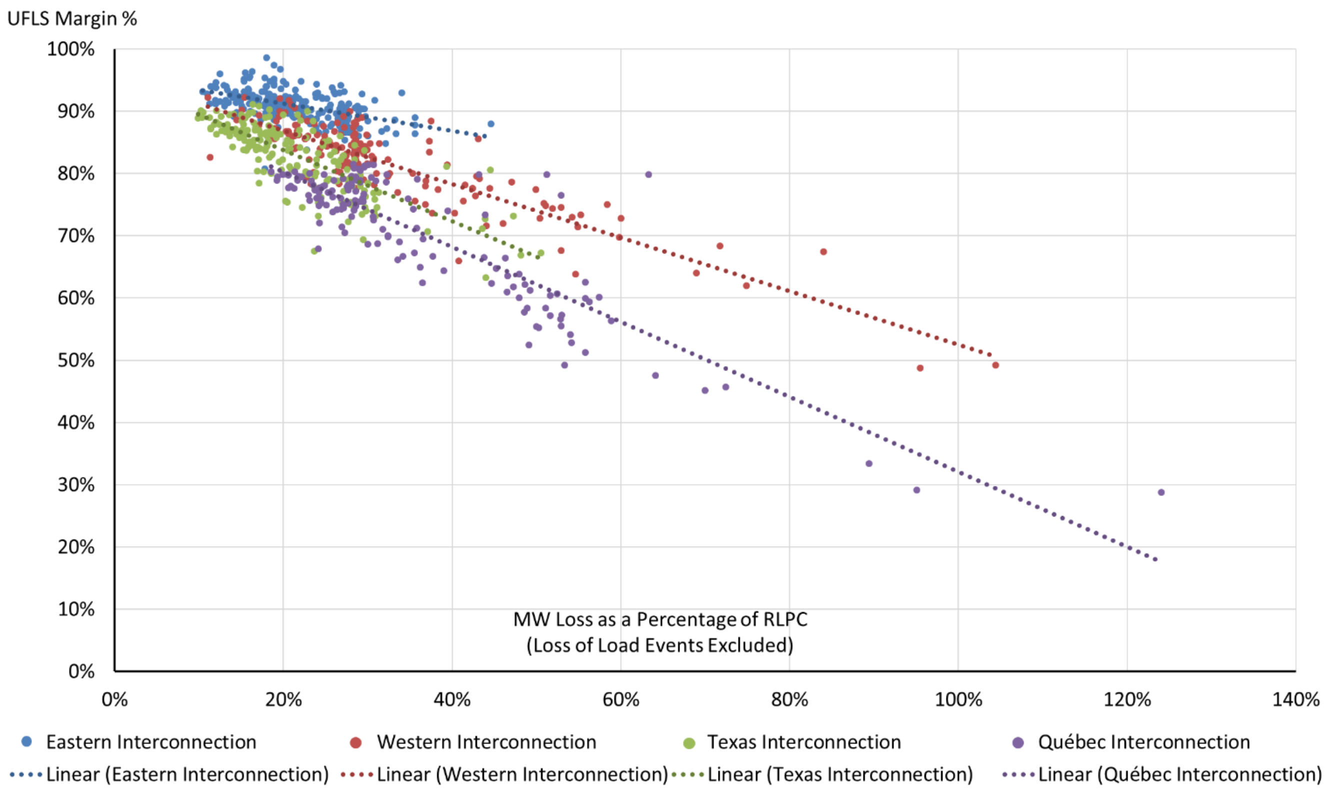


Figure 4.2: Operating Year 2018–2022 Qualified Frequency Disturbances and Remaining UFLS Margin

Disturbance Control Standard Metric

2022 Performance and Trends

In 2022, the total number of reportable balancing contingency events (RBCE) was slightly less than 2021 and less than the years 2020 and 2021. [61] Over the last five years, the average percent recovery was 99.2%. In 2022, there were three events where the BA did not restore its system to pre-disturbance levels within the contingency event recovery period. Although three events is a significant increase compared to what has occurred in the past, the BES was not put into an unstable condition. When these events are reviewed, it shows that the largest of the three events only missed the recovery period by eight seconds. Another of the events had underlying issues that masked the event from being recognized as an actual event. The magnitude of the event was approximately half of the entities most severe single contingency and only qualified as a reportable event because the BA is located in an area with a very low qualifying threshold. It should also be noted that this BA had reserves in excess of twice as large as the contingency available at the time of the event. See Figure 4.3 and Figure 4.4.

[61] Prior to December 31, 2017, NERC Reliability Standard BAL-002-1 required that a BA or reserve sharing group report all disturbance control standard events and non-recoveries to NERC. On January 1, 2018, NERC Reliability Standard BAL-002-2 became effective and no longer requires all RBCES to be reported to NERC. The disturbance control standard data used for 2018–2021 is from voluntary submissions from the BAs and reserve sharing groups.

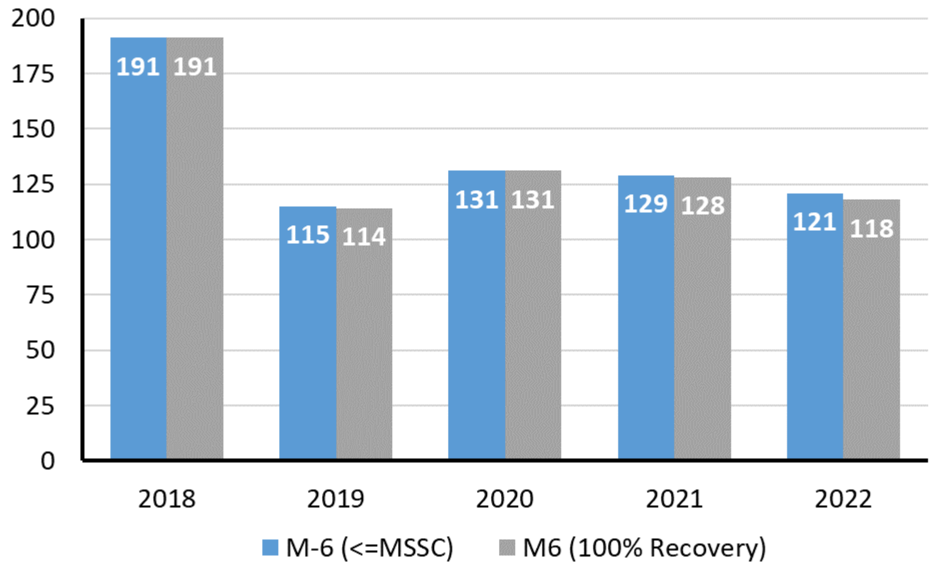


Figure 4.3: Total Number of RBCEs[62]

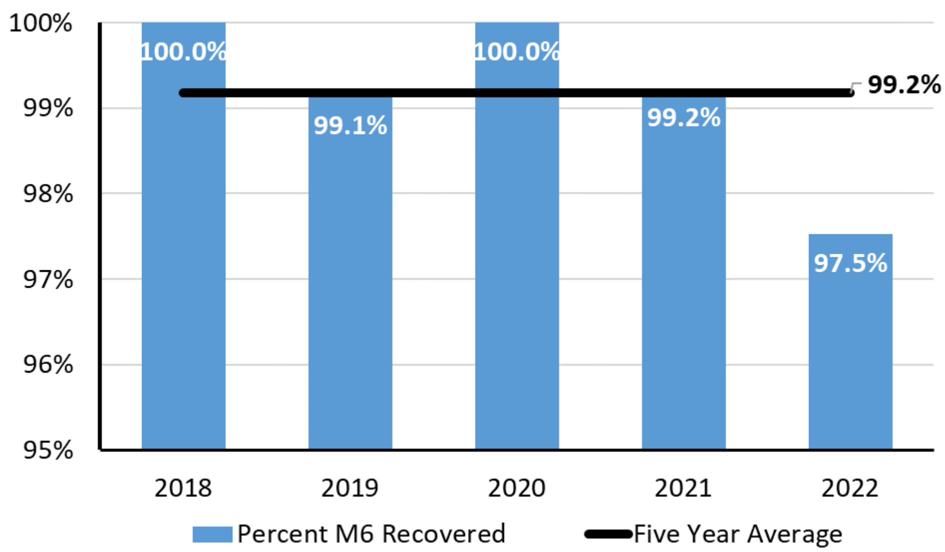


Figure 4.4: Percent of RBCEs with 100% Recovery

Interconnection Reliability Operating Limit Exceedances

2022 Performance and Trends

Each Reliability Coordinator has a different methodology to determine Interconnection reliability operating limits (IROL) based on the make-up of their area and what constitutes an operating condition that is less than desirable. The following discussion of performance on an Interconnection basis is for clarity, not for comparison:

- **Eastern–Québec Interconnections:** In 2022, there were 15 exceedances that lasted more than 10 minutes, which was less than the five-year average of 18 exceedances as shown in Figure 4.5. The 10-minute to 20-minute range continued to decline from its all-time peak in 2019. There were 4 exceedances greater than 20 minutes.
- **Western Interconnection:** The trend has been stable with no IROL exceedances reported in 2022.

[62] M-6 is the total number of reportable balancing contingency events (RBCE). M6 is the count of BAs that restored their systems to pre-disturbance levels within the contingency event recovery period.

- **Texas Interconnection:** In October 2020, ERCOT made a change to its system operating limit methodology that increased the number of IROLs for the Interconnection from one to five. In 2022, there were no exceedances greater than 10 minutes.

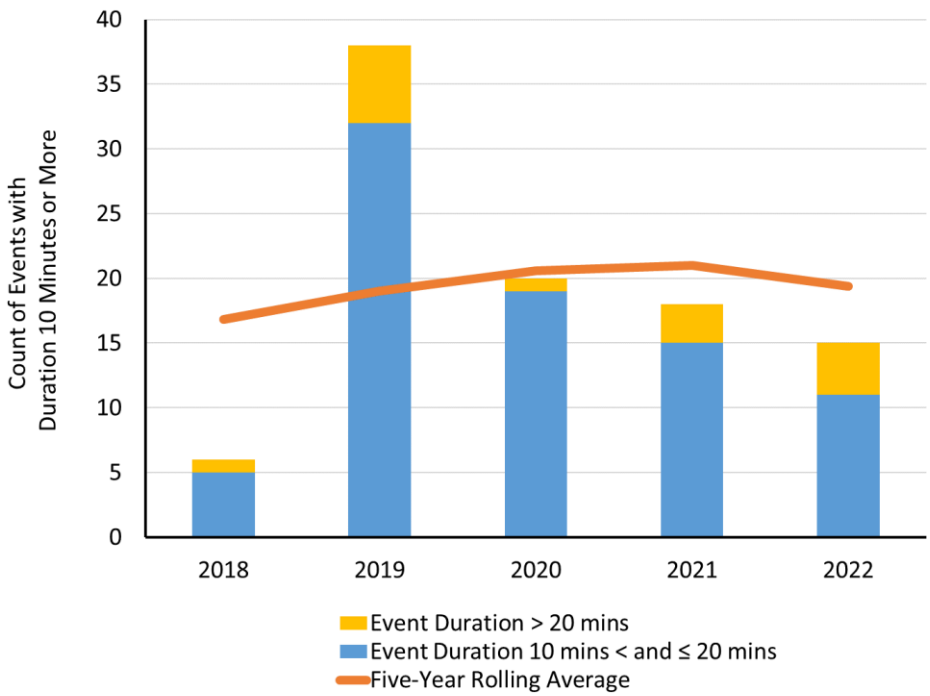


Figure 4.5: IROL Exceedance Counts

Generation Performance and Availability

GADS contains information that can be used to compute reliability measures, such as WEFOR. GADS collects and stores unit operating information by pooling individual unit information, overall generating unit availability, performance, and calculated metrics. The information supports equipment reliability, availability analyses, and risk-informed decision making to industry. Industry uses reports and information from the data collected through GADS for benchmarking and analyzing electricity power plants.

Conventional Generation WEFOR

The horizontal lines in **Figure 4.6** show the annual WEFOR compared to the monthly WEFOR columns; the solid horizontal bar shows the WEFOR for all years in the analysis period of 7.4% (notably lower than the 2022 WEFOR of 8.5%), a further increase from last year's rate of 8.3%. The WEFOR has been increasing over the last three years with the 2022 annual WEFOR being the highest of the last five years. The increase compared to prior years is primarily attributable to the December cold weather event and monthly WEFOR values that were an average of 0.4% higher.

Further correlative analysis indicates a moderate positive statistical correlation between the number of unit starts and forced outage counts for coal units as well as a moderate negative correlation between their age and number of service hours. A positive correlation between service hours and net maximum capacity was also identified when considering all fuel types.

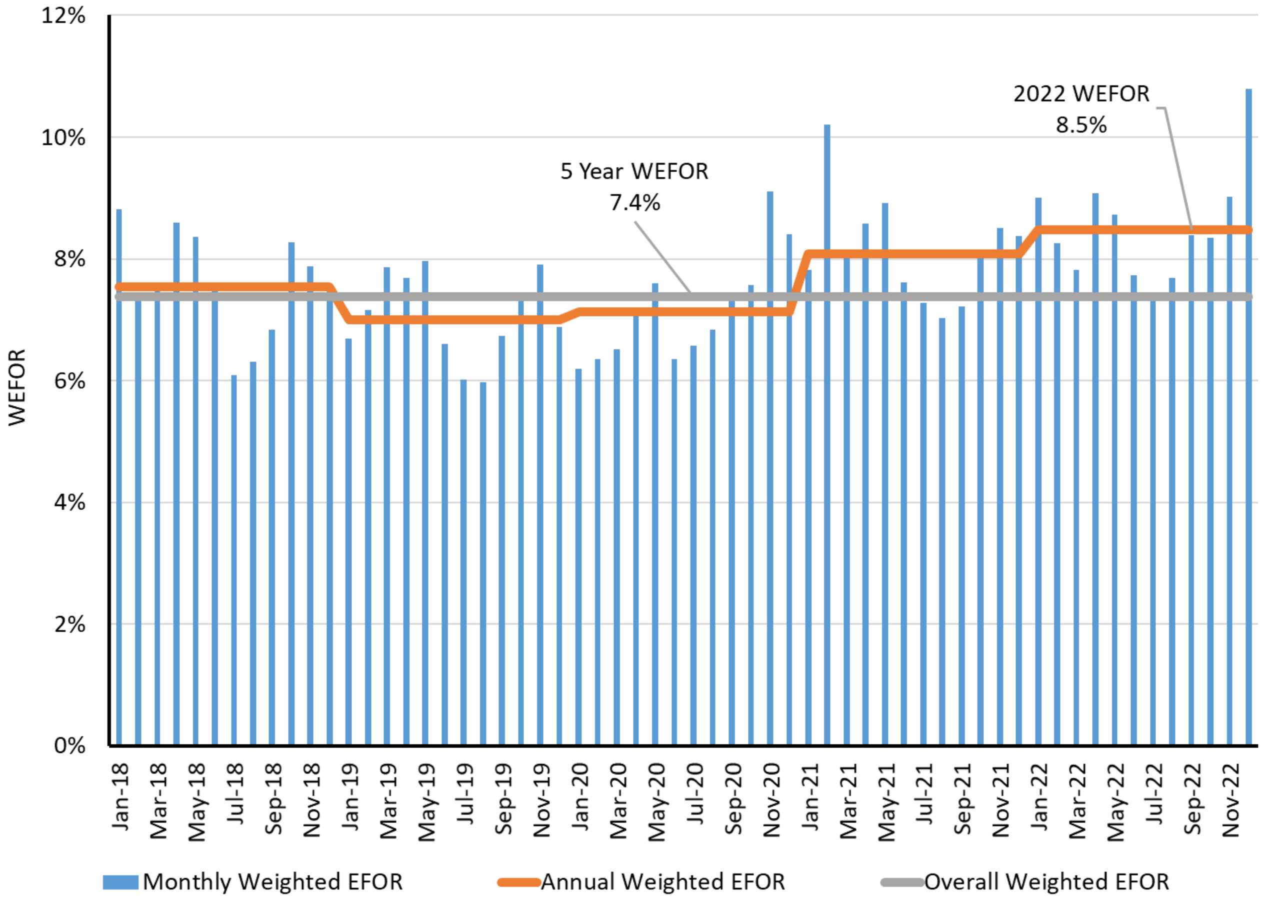


Figure 4.6: Monthly, Annual, and Five-Year WEFOR

The monthly WEFOR for select fuel types is shown as a layered area chart in **Figure 4.7**. The dashed line shows the monthly WEFOR of all fuel types reported to NERC, and the yellow line shows the mean outage rate of all fuel types reported to NERC over the five years in the analysis period. Coal-fired generation continues to show an increasing trend over the five-year period with a monthly average increase of 1.52% compared to 2021 and represents the highest forced outage rate of all major contributing conventional fuels, except during specific days of extreme winter weather when gas-fired generation outages generally spike above coal. Gas-fired generation also saw an average increase of 0.52% with all months being higher than 2021 except February and May.

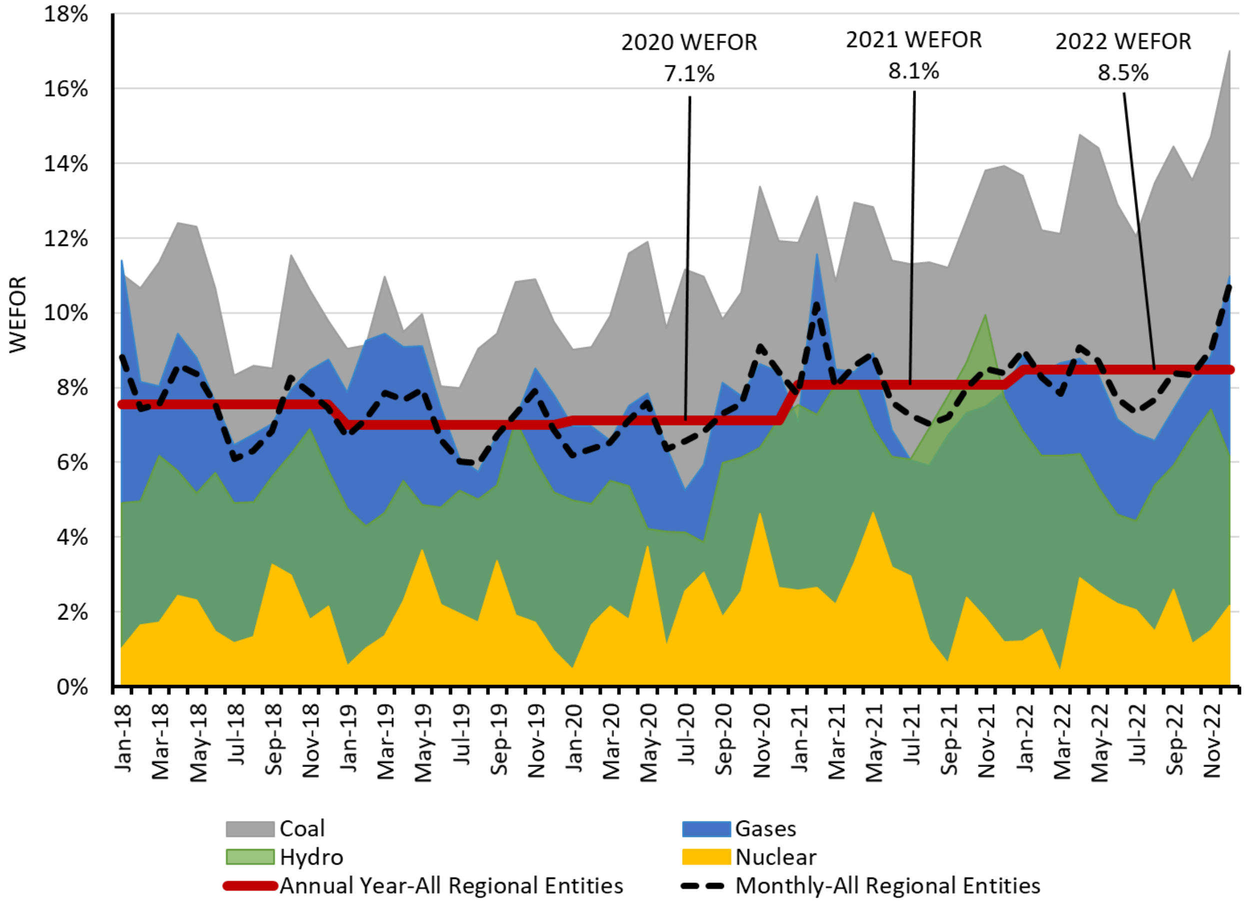


Figure 4.7: 2022 Monthly Weighted WEFOR by Fuel Type

Wind Generation Weighted Resource Equivalent Forced Outage Rate

NERC began collecting wind performance data with a phased-in approach based on plant size starting with a total installed capacity of 200 MW or greater in 2018 followed by plants with a total installed capacity of 100–199 MW in 2019 and plants with a total installed capacity of 75–99 MW in 2020. By the end of 2022, data from 120,100 MW of installed capacity (representing 640 wind plants across North America) was reported to NERC. Data will continue to be reported separately for the reporting phase groups until sufficient history is available to analyze trends for a five-year rolling period across all wind plants comparable to the analysis for conventional generation.

The weighted resource equivalent forced outage rate (WREFOR) for wind generation, which is analogous to WEFOR for conventional generation, is shown in Figure 4.8. The horizontal lines show the annual WREFOR compared to the monthly WREFOR columns based on the data provided during phased-in reporting periods according to plant size. Seasonal trends, such as the increased outage rates during summer and winter months and lower forced outage rates in spring, are evident.

The WREFOR was up slightly since 2021 for wind plants between 75 and 199 MW while plants over 200 MW saw a decrease in 2022. In 2022, both August and December saw unusually high WREFORs in correlation with widespread high and low temperatures, respectively.

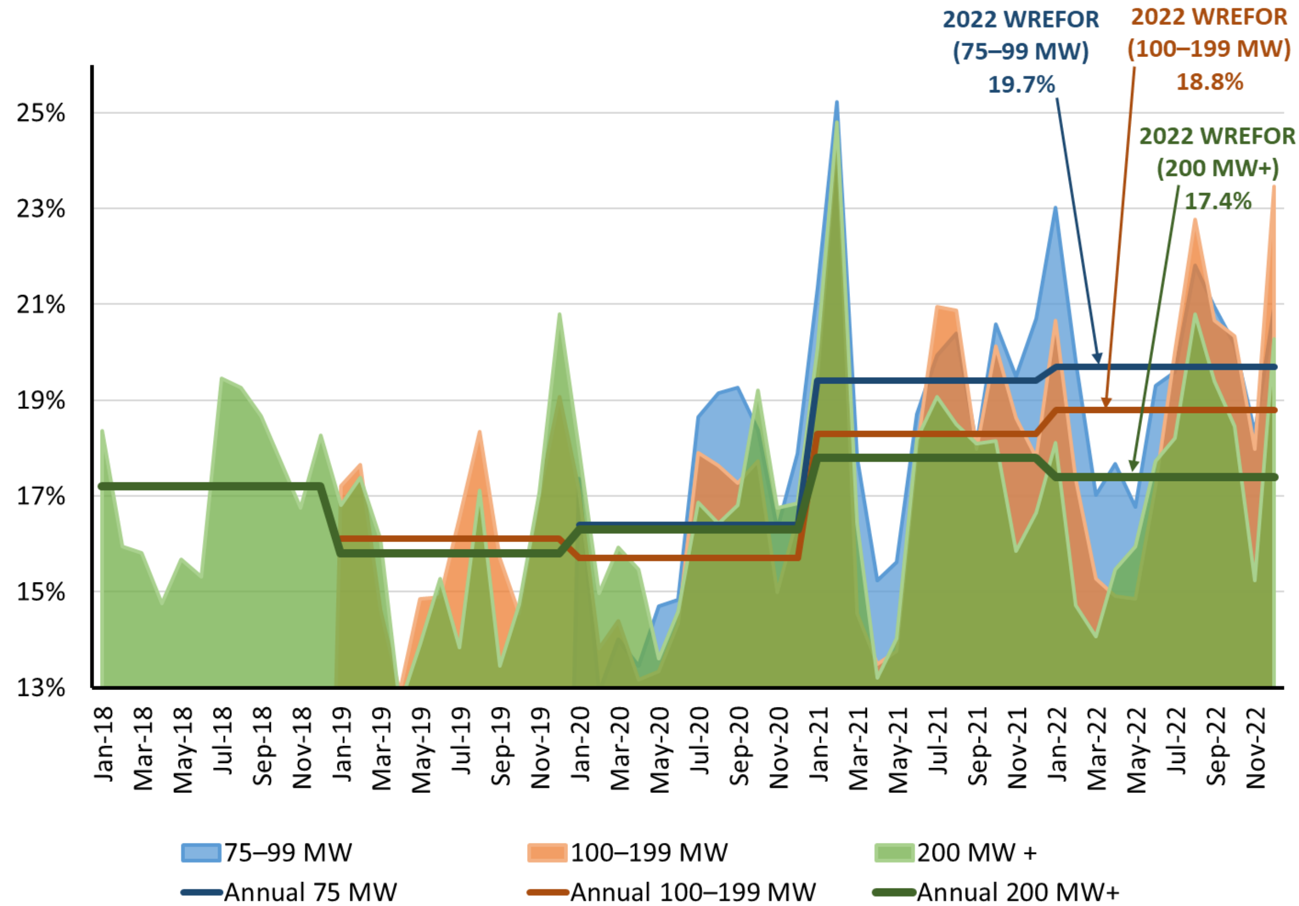


Figure 4.8: Monthly Capacity WREFOR and Annual Average Wind Plant Reporting Group

Transmission Performance and Unavailability

When evaluating transmission reliability, an important concept is that transmission line outages have different impacts on BPS reliability. Some impacts can be very severe, such as those that affect other transmission lines and load loss. Additionally, some outages are longer than others, leaving the transmission system at risk for extended periods of time. Reliability indicators for the transmission system are measured by using qualified event analysis reporting not related to weather and outages reported to TADS. The number of qualified events that include transmission outages that resulted in firm load loss not related to weather is provided in the following subsection.

Transmission-Related Events Resulting in Loss of Load

In 2022, a total of 10 distinct non-weather-related transmission events resulted in loss of firm load met the Event Analysis Process (EAP) reporting criteria (see **Figure 4.9**), representing an increase in the number of events over 2021. Analysis indicates no discernable trend in the number of annual events. The median firm load loss over the past five years was 101 MW, which is a decrease from 2017–2021's 131 MW. In 2022, the median was 83 MW with a stable median load loss remaining below the five-year median value.

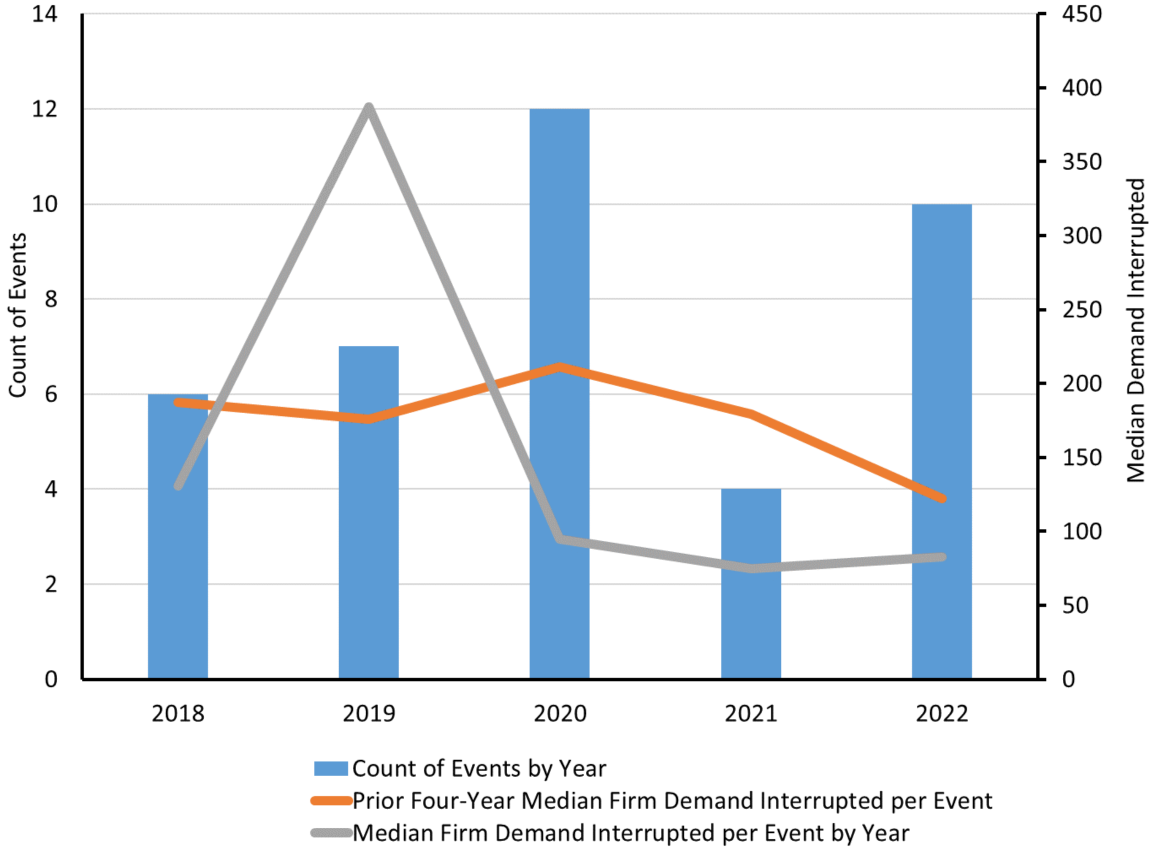


Figure 4.9: Transmission-Related Events Resulting in Loss of Firm Load and Median Amount of Firm Load Loss Excluding Weather-Related Events

TADS Reliability Indicators

A TADS event is an unplanned transmission incident that results in the automatic outage (sustained or momentary) of one or more elements. TADS event information was analyzed for the following indicators in this section:

- **Transmission Outage Severity**
- **Automatic AC Transmission Outages**
- **Automatic AC Transformer Outages**
- **Transmission Element Unavailability**

Transmission Outage Severity

The impact of a TADS event on BPS reliability is called the transmission outage severity (TOS) of the event, which is defined by the number of outages in the event and by the type and voltage class of transmission elements involved in the event. TADS events are categorized by initiating cause codes (ICC). These ICCs facilitate the study of cause-effect relationships between each event's ICC and event severity.

By examining the average TOS, duration, and frequency of occurrence for events with different ICCs (see **Figure 4.10**), it is possible to determine which ICCs contribute most to reliability performance for the considered time period. The average TOS for an ICC's events is displayed on the Y-axis. A higher TOS for an ICC indicates more outages or higher voltage elements were involved in an event. The average duration for a given ICC's events is displayed on the X-axis; generally, events with a longer duration pose a greater risk to the BPS. The number of ICC occurrences is represented by the bubble size; larger bubbles indicate an ICC occurs more often. Change in size or position of a bubble with the same number (identifying ICC) may indicate improved or declined performance. Lastly, the bubble colors indicate a statistical significance of a difference in the average TOS of this group and the events from other groups.

There was a statistically significant reduction in the average event TOS and duration from 2017–2021 to 2018–2022 (past five-year period to the current five-year period), indicating an improvement in the TOS and duration sub-metrics.

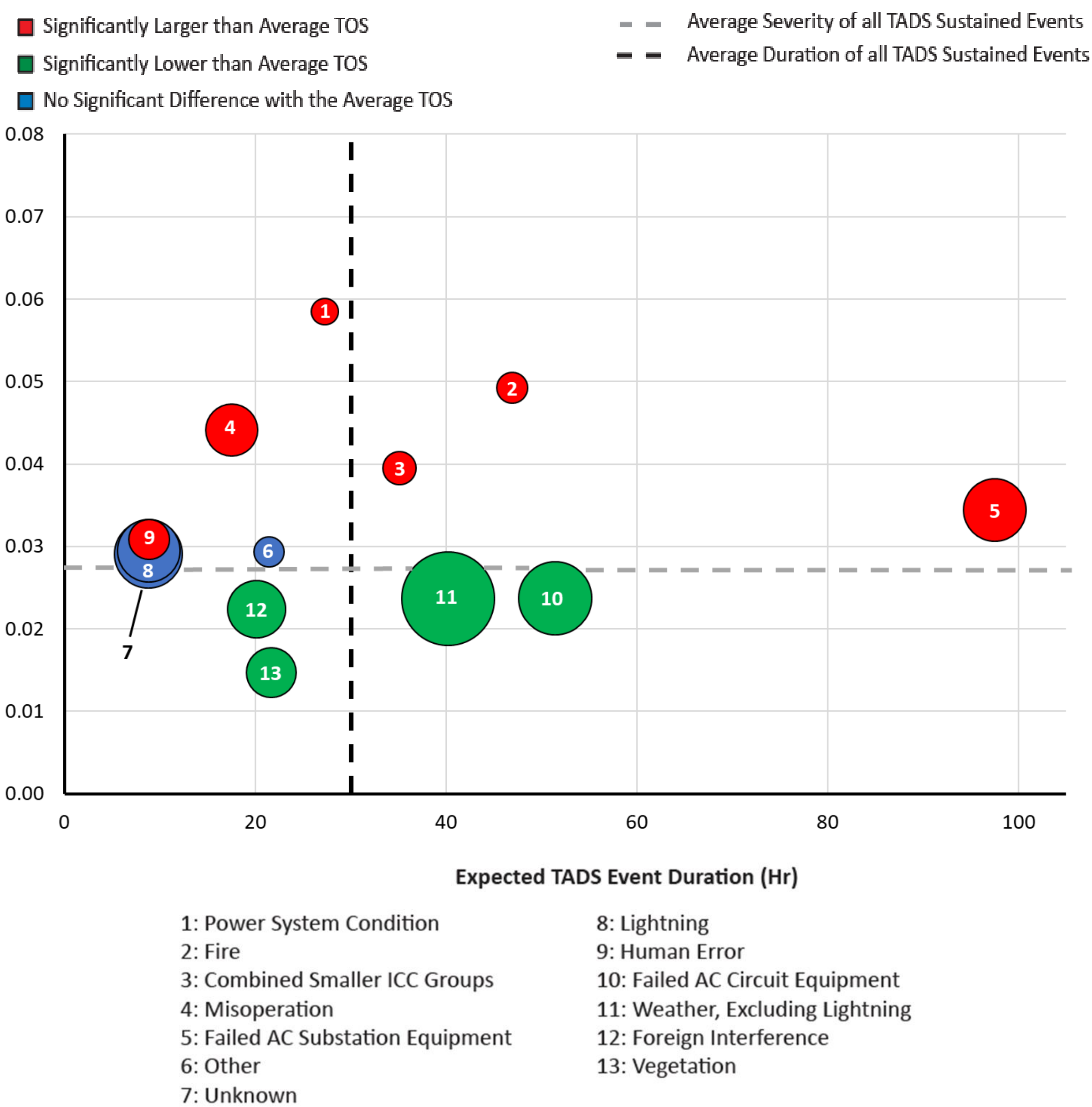


Figure 4.10: TOS vs. Expected TADS Event Duration

An analysis of the total TOS by year indicates a statistically significantly improving trend for the last five years (see Figure 4.11); this is a positive indication that transmission outages are leading to less severe reliability impacts.

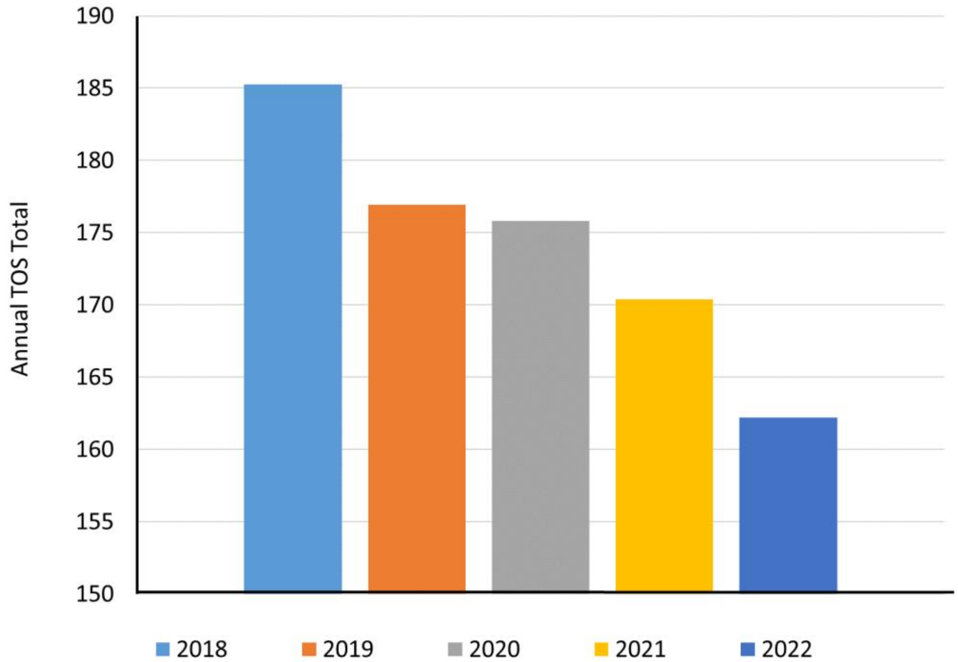


Figure 4.11: TOS of TADS Sustained Events of 100 kV+ AC Circuits and Transformers by Year

Automatic AC Transmission Outages

The average number of outages per circuit due to Failed AC Substation Equipment has continued to improve consistently over the last four years, showing a statistically significant decrease in 2022 compared to 2018–2021 (See **Figure 4.12**). The number of sustained outages due to Failed AC Circuit Equipment per 100 miles saw a slight decrease, bringing it just below the five-year average; however, it remains stable overall (see **Figure 4.13**).

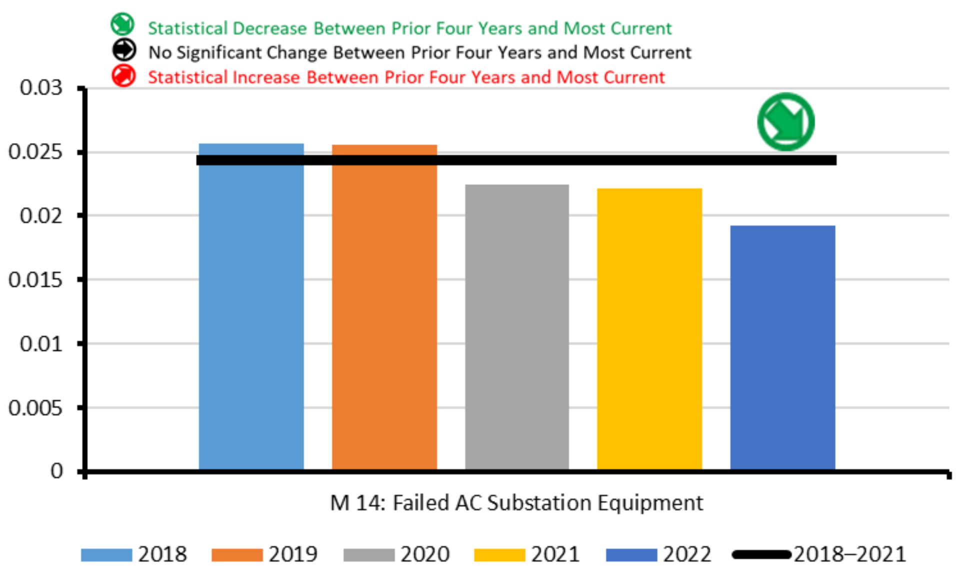


Figure 4.12: Number of Outages per AC Circuit due to Failed AC Substation Equipment

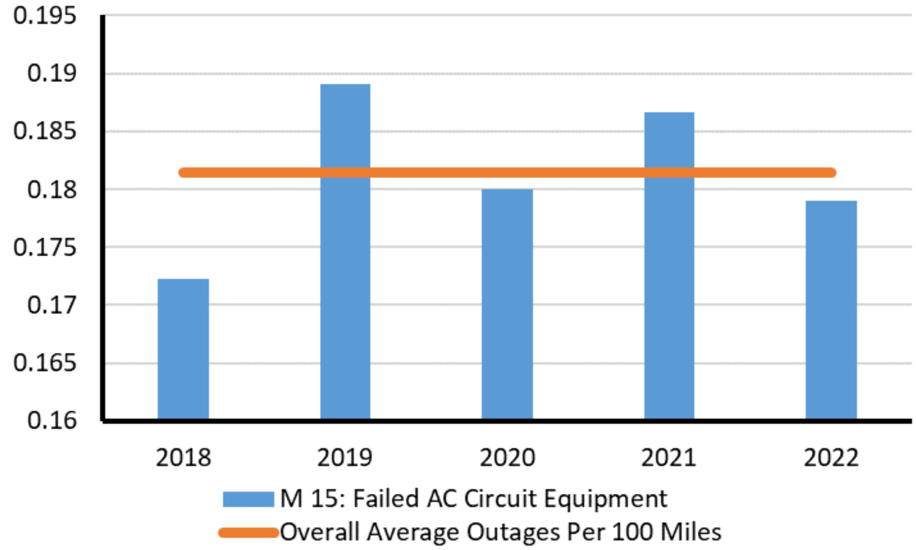


Figure 4.13: Number of Outages per Hundred Miles due to Failed AC Circuit Equipment

Automatic AC Transformer Outages

In 2022, the number of automatic ac transformer outages per element caused by Failed AC Substation Equipment showed an increase that was not statistically significant when compared to 2018–2021 (see **Figure 4.14**).

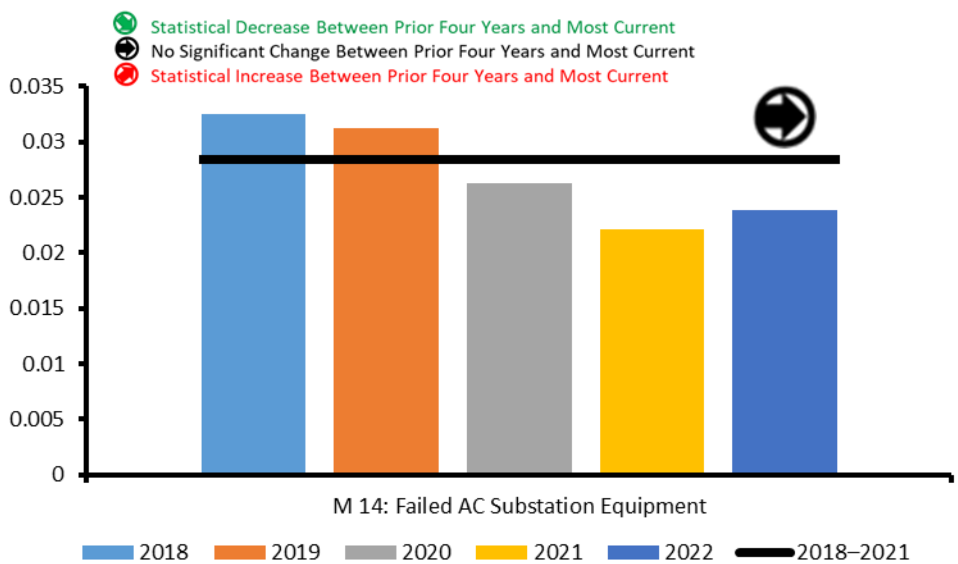


Figure 4.14: Number of Outages per Transformer Due to Failed AC Substation Equipment

Transmission Element Unavailability

In 2022, ac circuits over 200 kV across North America had an unavailability rate of 0.254%, meaning that there is a 0.254% chance that a specific transmission circuit is unavailable due to sustained automatic and operational outages at any given time. Transformers had an unavailability rate of 0.22% in 2022. **Figure 4.15** shows 2022 was the second lowest year for ac circuit unavailability of the five-year analysis period. **Figure 4.16** shows 2022 was the middle year of the five observed.

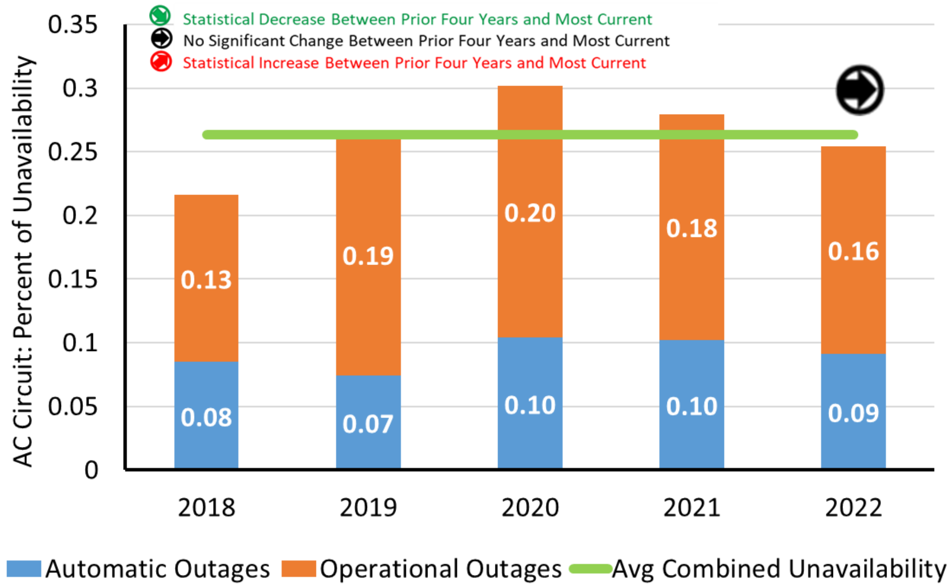


Figure 4.15: AC Circuit Unavailability

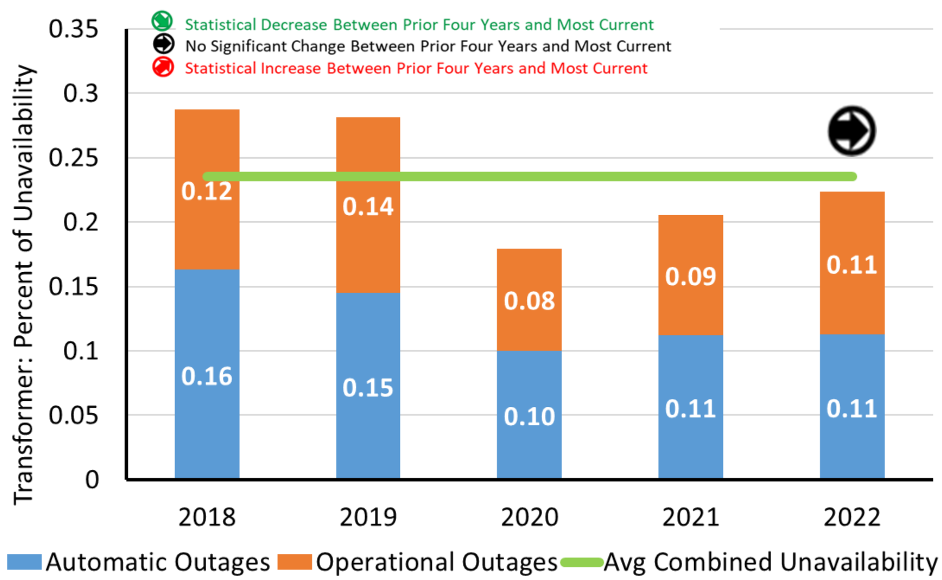


Figure 4.16: Transformer Unavailability

Loss of Situational Awareness

The BES operates in a dynamic environment with physical properties that are constantly changing. Situational awareness is necessary to maintain reliability, anticipate events, and respond appropriately when or before events occur. In order to maintain the reliability of the BES, entities use various situational awareness tools that include, but are not limited to, energy management systems (EMS), transmission outage planning, load forecasting, geomagnetic disturbance/weather forecasting, data from neighboring entities' operations, and interpersonal communication within their own companies and with neighboring systems.

Without the appropriate tools and up-to-date data, system operators may have degraded situational awareness that impacts their ability to make informed decisions that ensure reliability of the BES. Unexpected outages of systems needed for communications, monitoring and control of equipment, or planned outages without appropriate coordination or oversight can leave system operators with reduced visibility. For system operators, the EMS is a critical component of situational awareness.

At the same time, security risks have implications for industry that require a broadened perspective from what was traditionally addressed in conventional engineering practices, such as planning, design, and operations. The ERO *Reliability Risk Priorities Reports*[63] of 2019 and 2021 both highlighted security risks as one of the four top risks for the electricity sector with cyber security risks identified as the most likely to impact the industry.

The ERO is focused on working collaboratively with industry stakeholders to develop recommendations for integrating security with engineering practices, particularly related to developing cyber engineering capabilities that integrate these practice more holistically.

Impacts from the Loss of EMS

An EMS is a computer-aided set of tools used by system operators as a primary means to monitor, control, and optimize the performance of the generation and/or transmission system. The EMS allows system operators to monitor and control frequency, the status (open or closed) of switching devices plus real and reactive power flows on BES tie-lines and transmission facilities within the respective control area, and the status of critical applicable EMS applications (e.g., state estimator (SE), real-time contingency analysis (RTCA), automatic generation control, alarm management).

There were 52 categorized events associated with an EMS in 2022. In total, 322 EMS-related event reports were submitted between 2018 and 2022; there were no reported EMS-related events that caused loss of generation, transmission lines, or customer load. **Figure 4.17** shows a trend of the reported EMS events by loss of EMS functions over the 2018–2022 period.

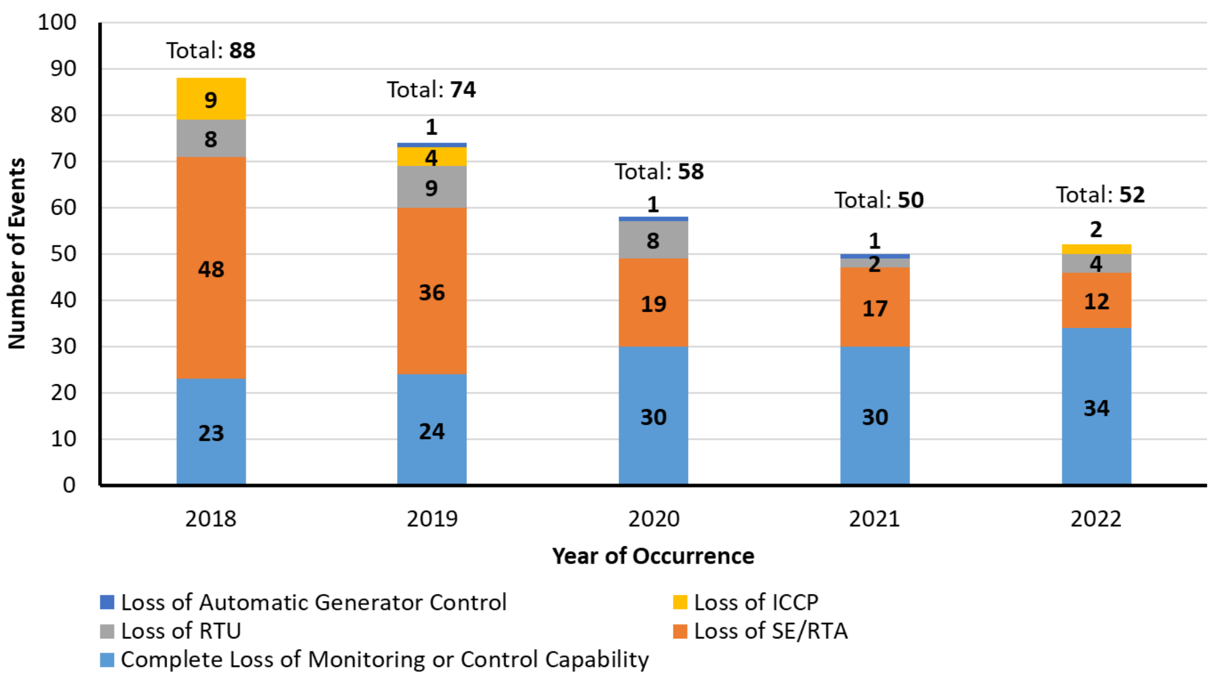


Figure 4.17: Number of EMS-Related Events (2018–2022)

Both loss of SE/RTCA and Inter-Control Center Protocol (ICCP) events have been declining since 2018. There are two significant reasons for the declining trend of loss of SE/RTCA and ICCP:

- Partial loss events (i.e., loss of SE/RTCA, loss of ICCP, loss of remote terminal units, and loss of automatic generation control) are no longer captured as part of EOP-004-4 mandatory reporting. However, the ERO

[63] *2019 ERO Risk Priorities Report*, November 2019: https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC%20ERO%20Priorities%20Report_Board_Accpeted_November_5_2019.pdf

encourages partial loss EMS reporting through the EAP for trending of potential reliability risks/impacts to the BES as some entities continue to do.

- The industry has made significant effort to enhance EMS reliability and resilience. For example, many entities built a 24x7 onsite team that works along with system operators and provides dedicated support to SE and RTCA. This action has significantly reduced the outage duration resulting in many SE/RTCA issues not being reportable.

The complete loss of monitoring or control capability events was in an increasing trend over the 2018–2022 period. The following observations and recommendations were made during analysis of the EMS events:

- **Network Communications Configuration**
  EMS-related communications networks are moving from point-to-point serial communication infrastructures to packet-based networks. The main advantage of a packet-based network is to transmit data from one node to another node while avoiding a communications system failure caused by the breakdown of a single (or few) intermediate link(s). Consequently, the correct configuration is critical to ensure the communications network functions as designed.
- **Power Supply**
  Stable and secure power supplies are critical to control rooms, data centers, and substations. Although the redundant power supply was installed at the control rooms, data centers, and substations, it is essential that routines be established for monthly testing and maintenance of the backup generator, uninterruptible power supply, and associated power switches.
- **Dealing with Abnormal Working Environment**
  Entities implemented work-from-home policies for non-essential employee in 2020. Lots of tasks (e.g., maintenance, software/database deployment) that normally were conducted onsite had to be executed in a remote fashion. Job scoping needs improvement to involve all potentially impacted groups and departments and strengthen peer review of design, implementation, and testing.

Over the five-year period, the average partial or full function EMS outage time (see **Figure 4.18**) was 70 minutes, making the calculated reported EMS availability 99.993%.

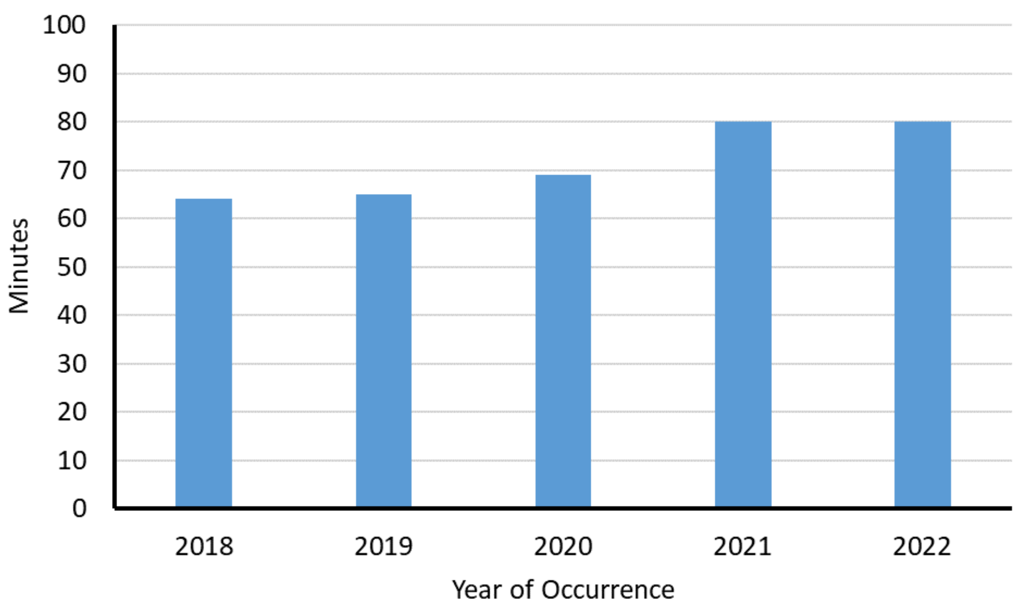


Figure 4.18: Average EMS Outage Time (2018–2022)

Largest Contributor to Loss of EMS

Reported EMS events can be grouped by the following attributes:

- **Software**: Software defects, modeling issues, database corruption, memory issues, etc.
- **Communications**: Devices issues, less than adequate system interactions, etc.
- **Facility:** Loss of power to the control center or data center, fire alarm, ac failure, etc.
- **Maintenance:** System upgrades, job-scoping, change-management, software configuration, or settings failure, etc.

Figure 4.19 shows that, over the evaluation period from 2018–2022, outages associated with software and communications challenges were the leading contributors to EMS outages.

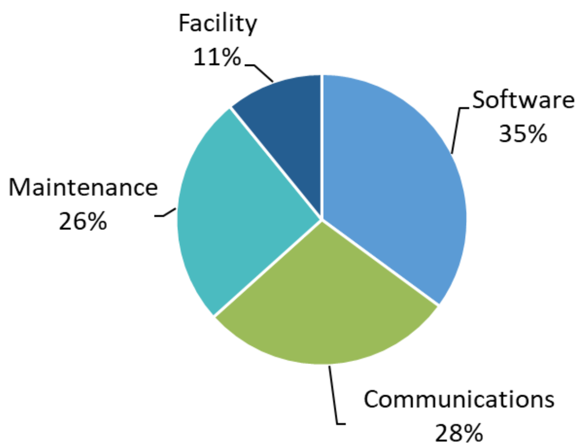


Figure 4.19: Contributors to Loss of EMS Functions (2018–2022)

Software failure usually was caused by bugs either in a vendor application or in an in-house implementation. A completed software testing process is always recommended to guarantee that the software meets its requirements. Systems and software assurance requires a process model for formal testing based upon the software development framework that the software was created within. The scope of the test should provide an assurance case for operation of the software under test for both known and unknown operating conditions with the inclusion of a data integrity check of the module. In general, the process is considered to have four components:

- **Test Scope:** Define the test environment requirements and setup, features/functions that need to be tested, documentation to refer and produce as output, approval workflows, etc.
- **Test Design:** Design the test cases that are necessary to validate the system/functions/features being built compared to its design requirements. Typically, regression testing and incremental testing are necessary
- **Test Execution:** Execute tests in many different ways
- **Test Closure:** Consider the exit criteria for signaling completion of the test cycle and readiness for release

Communications failure means that data exchange was degraded between substations and control rooms or between the entity and its Reliability Coordinator/neighboring entities. Internal network configuration error and hardware failure are two major contributors to this cause. Entities should maintain network devices on a schedule in accordance with the latest vendor information, security bulletins, technical bulletins, and other recommended updates. Entities must also consider redesigning communications systems such that the most critical BES substations communicate simultaneously over entirely separate physical paths to control centers.

A review of ERO EAP data shows that a total of 6.8% or 22 out of the 322 reportable loss of EMS events greater than 30 minutes were related to external communication provider issues between 2018 and 2022. Presently, external communication provider related issues are not influencing EMS outages in a major way.

Assessment

Software and communications failure are major contributors to the loss of EMS. The loss of ability to monitor and/or control at least part of an entity's system is the most prevalent failure over the evaluation period from 2018–2022. Both loss of SE/RTCA events and loss of ICCP events have been declining since 2018 due to the EOP-004-4 impact on partial loss of EMS functions reporting and the industry effort to enhance EMS reliability and resilience.

While failure of a situational awareness tool has not directly led to the loss of generation, transmission lines, or customer load, EMS failures may hinder the decision-making capabilities of the system operators during normal operations or during a disturbance. The ERO has analyzed data and identified that short-term outages of tools and monitoring systems are not uncommon and that the industry is committed to reducing the frequency and duration of these types of events.

Increasing Complexity of Protection and Control Systems

Protection and Control Systems

As the system of interconnected power generation, transmission, and distribution assets has evolved, so too has the numbers and types of automated tools and systems that use digital information and microprocessor-driven devices to manage the electricity grid. This technologically diverse environment allows an operator to manage specified controls from virtually anywhere and at a cost far lower than what would have been possible otherwise. When designed and implemented properly, automated tools can enhance the reliable and secure use of new technologies and concepts that become available. On the other hand, maintaining, prudently replacing, and upgrading BPS control system assets can lead to protection system and control system misoperations, such as when updated settings are issued. Misoperations can initiate more frequent and/or more widespread outages. Resource mix changes that involve growth in inverter-based generation sources can also impact wide-area protection and increase the need to coordinate protection with the distribution system.

By evaluating the annual misoperation rates across North America and separately for each Regional Entity over the last five years and comparing the misoperation rate of the first four years with the most recent year (see **Figure 4.20**), a statistically significant decreasing trend can be observed in the misoperation rates for RF and the overall MIDAS data reported to NERC. No statistically significant trend is observed for MRO, NPCC, SERC, or WECC. A statistically significant increase in the misoperation rate for Texas-RE occurred in 2022, analysis indicates this increase is due to a decrease in protection system operations that is not reflected in the misoperations count, supported by a slight increase in misoperations caused by incorrect settings, relay failures, and communication failures misoperations (see **Table 4.3**).

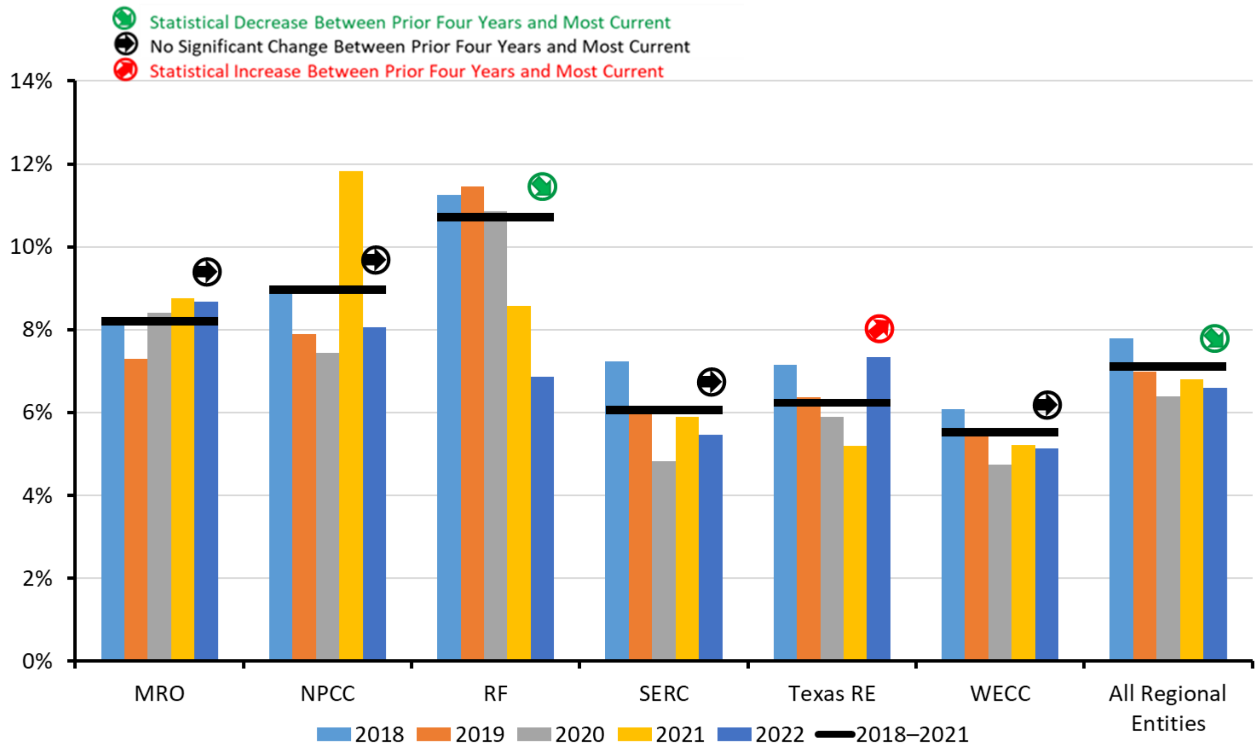


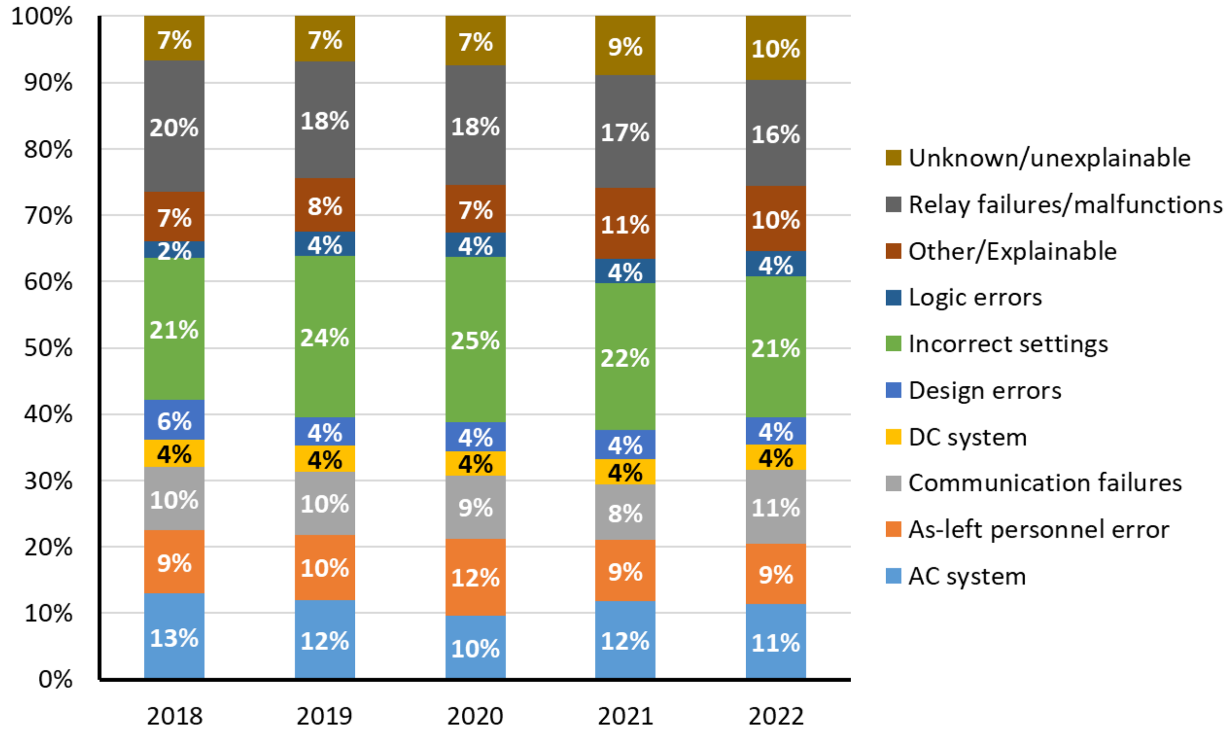
Figure 4.20: Changes and Trends in the Annual Misoperations Rate by Regional Entity

Table 4.3: Five-Year Protection System Operations and Misoperations Counts 2018 through 2022

Area	Protection System Operations					Misoperations				
	2018	2019	2020	2021	2022	2018	2019	2020	2021	2022
All Regional Entities	19,744	19,283	18,296	17,448	17,769	1,536	1,346	1,170	1,186	1,170
MRO	3,740	3,734	3,054	2,617	3,240	306	272	257	229	281
NPCC	2,105	1,658	1,774	1,362	1,652	187	131	132	161	133
RF	2,275	2,146	1,878	1,866	2,055	256	246	204	160	141
SERC	4,873	4,736	5,267	4,614	4,764	352	284	254	272	260
Texas RE	2,280	2,640	2,000	2,599	1,992	163	168	118	135	146
WECC	4,471	4,369	4,323	4,390	4,066	272	245	205	229	209

Leading Causes of Misoperations

The top causes of misoperations over the past five years have consistently been Incorrect Settings and Relay Failures/Malfunctions (see **Figure 4.21**), and the relative frequency of these two causes has continued to slowly decrease in 2022. The year of 2022 also saw the continued increase in the number of misoperations coded as Unknown/Unexplainable, from 85 in 2020 to 110 in 2022.



Year	2018	2019	2020	2021	2022
Misoperation Count	1,536	1,346	1,170	1,186	1,170

Figure 4.21: Percentage of Misoperations by Cause Code (2018–2022)

Misoperation Impact Score

Over the past several years, the ERO has identified numerous scenarios in which referencing only the misoperation rate calculation does not provide an accurate representation of how entities' protection systems are performing. In order to provide a more holistic analysis of BES protection systems' performance, the ERO has worked with the MIDAS User Group to create a measure reflective of a misoperation's estimated impact to the BES. This calculation consists of factoring several fields that are reported into MIDAS and providing each option for those fields with a weight. Weights, shown in the equation below, and factors (see Table 4.4) were determined using existing regional calculations, with some adjustments following review. The resulting value, termed "misoperation impact score," is scalable down to the individual misoperation level and can be aggregated in a variety of ways to illustrate trends in misoperations' general impact to the BES.

$$[Misoperation\ Impact\ Score] = [\ Voltage\ Class\ Factor] * 0.3 + [Equipment\ Type\ Factor] * 0.2 + [Cause\ Factor] * 0.1 + [Category\ Factor] * 0.4$$

Table 4.4: Misoperation Impact Factors

Field	Value	Factor
Voltage Class	0–99 kV	0.4
	100–199 kV	0.5
	200–299 kV	0.65
	300–499 kV	0.85
	500–765 kV	1
Equipment Type	BES UFLS, BES UVLS	0.333
	Shunt Capacitor, Shunt Reactor/Inductor	0.5
	HVdc, Line, Series Capacitor, Series Reactor/Inductor, Transformer, Breaker	0.667

Table 4.4: Misoperation Impact Factors		
Field	**Value**	**Factor**
	Bus, Other	0.833
	Dynamic VAR Systems, Generator	1
Cause	Equipment Errors (and Other)	0.5
	Human Errors	0.85
	Unknown	1
Category	Slow Trip–Other than Fault	0.167
	Unnecessary Trip–Other than Fault	0.333
	Failure to Trip–Other than Fault, Unnecessary Trip–During Fault	0.667
	Failure to Trip–During Fault, Slow Trip–During Fault	1

The mean and median of all misoperations' impact scores (see **Figure 4.22**) have remained relatively similar over the past five years, indicating that the system as a whole has been performing similarly. The outer quartiles of impact scores has continually increased since 2019, indicating that the number of potentially high and low impact misoperations has experienced a slight, but steady, increase over that period. The misoperations in the higher impact quartile may warrant additional analysis for commonalities and targeted reduction.

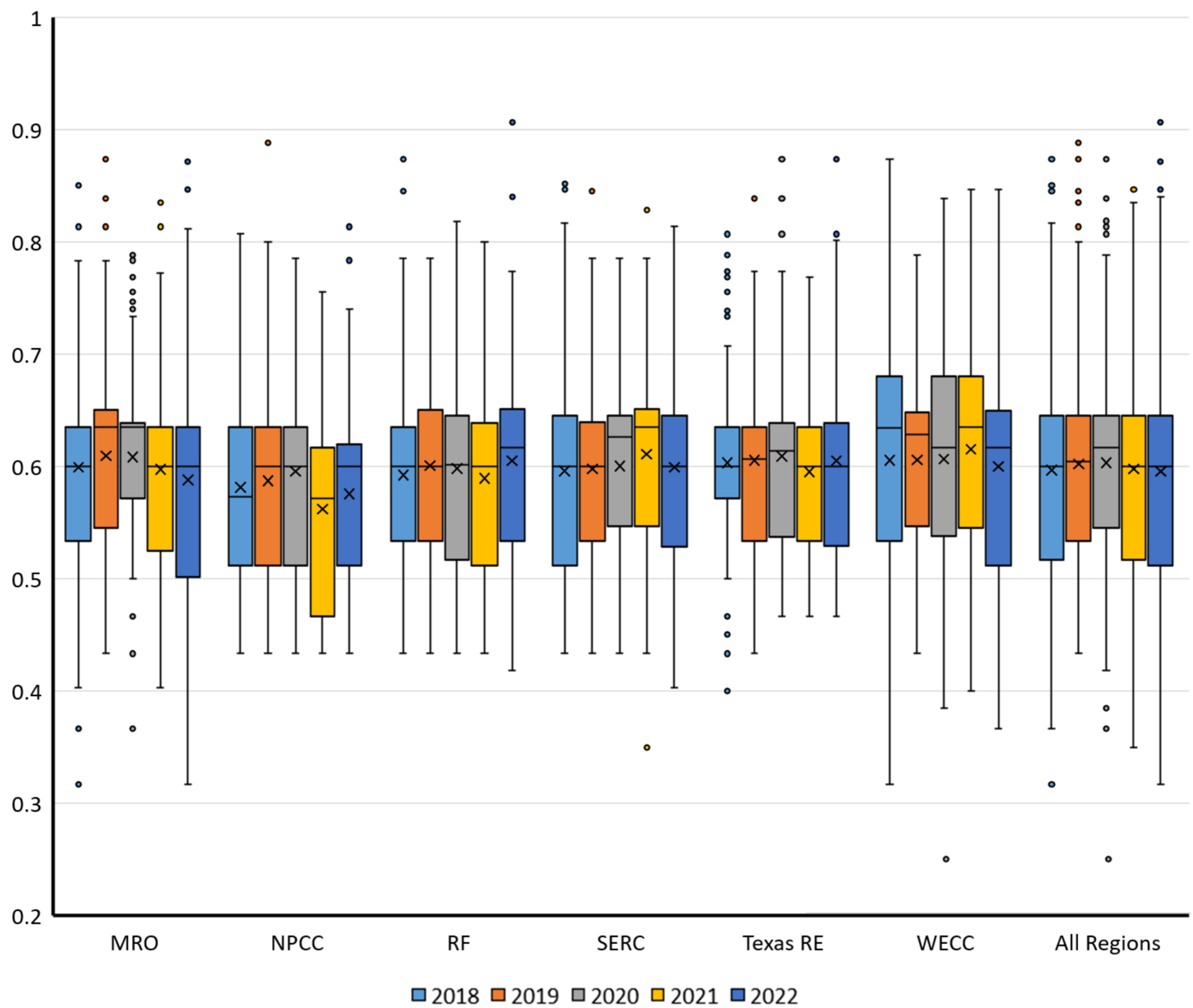


Figure 4.22: Misoperations Impact Score Distribution (2018–2022)

Protection System Failures Leading to Transmission Outages

AC circuits and transformers both saw a decrease in the number of outages per element in 2022, the number of outages per transformer was statistically significantly lower than the prior four years (see **Figure 4.23**).

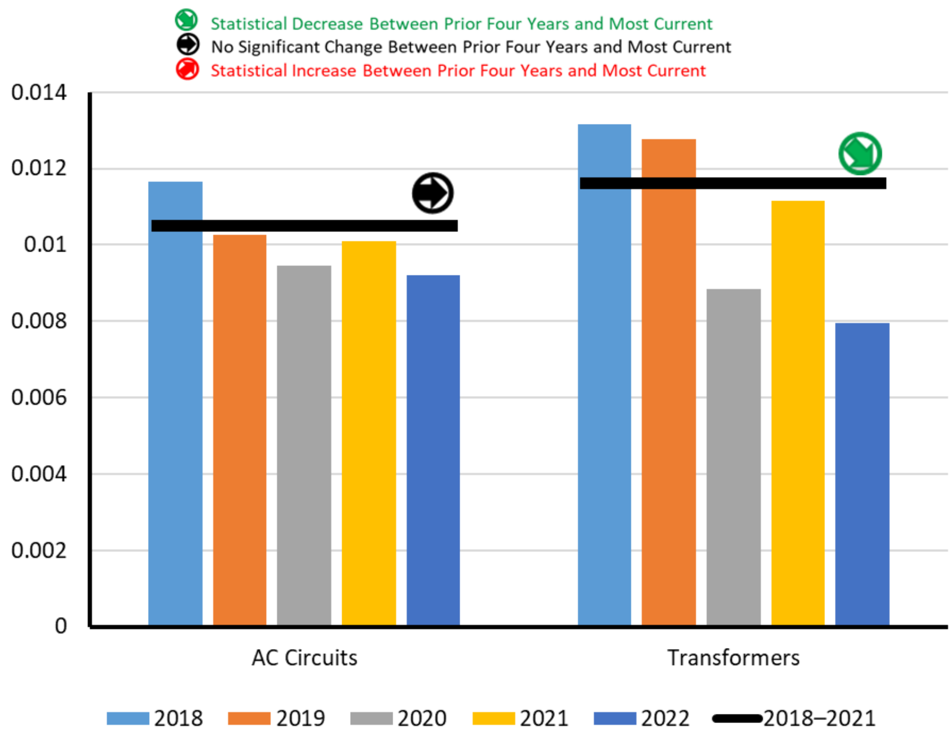


Figure 4.23: Failed Protection System Equipment Outages

Event-Related Misoperations

An analysis of qualified events reported through the ERO EAP found that there were 74 transmission-related system disturbances in 2018. Of those 74 events, a total of 47 events (64%) had associated misoperations. Since 2018, the ERO and industry stakeholders have continued efforts to reduce protection system misoperations through initiatives that included formation and participation in various task forces, workshops, and conducting more granular root cause analysis. In 2022, there were 71 transmission-related qualified events. Of those 71 events, 30 events (42%) involved misoperations (see **Figure 4.24**). The efforts made by the ERO and industry have resulted in a declining trend in the number of events with misoperations over the last five years.

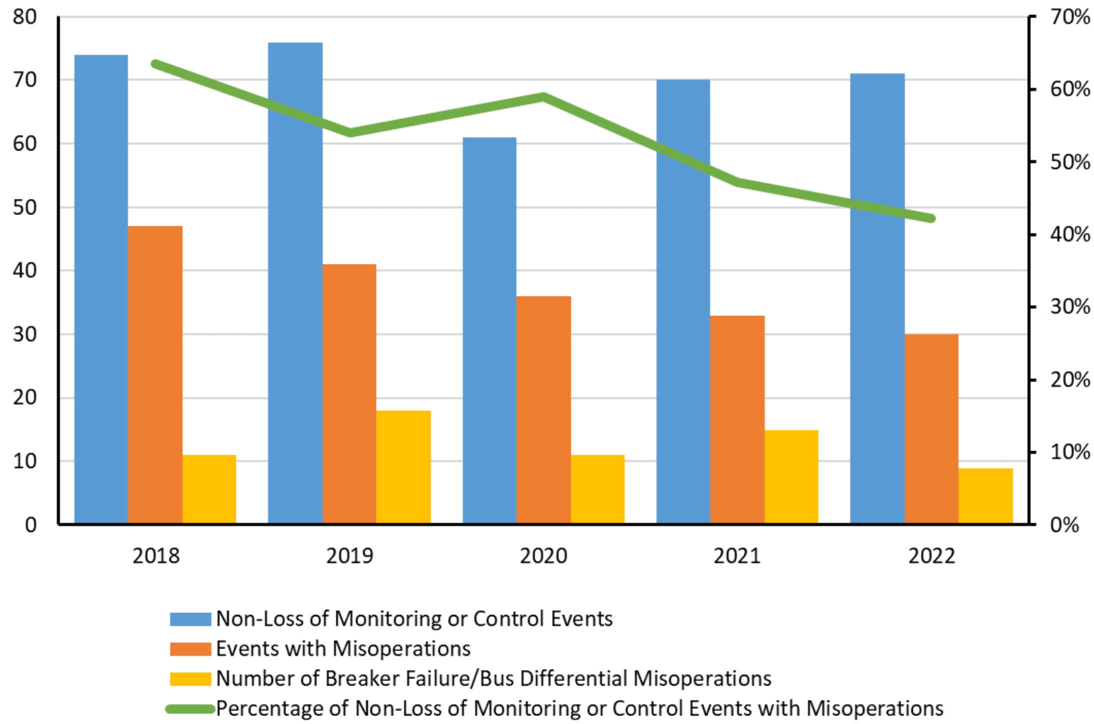


Figure 4.24: Events with Misoperations

Human Performance

Transmission Outages

NERC TADS collects transmission outage data with a variety of causes that include Human Error. The definition of Human Error as a cause of transmission outage is defined in the *TADS Data Reporting Instructions*.[64] The effective use of human performance will help mitigate the active and latent errors that negatively affect reliability. Weaknesses in human performance hamper an organization's ability to identify and address precursor conditions that degrade effective mitigation and behavior management.

Statistical significance testing was done that compared 2022 to the average outage rate of the prior four years. For ac circuits, all operational outages caused by Human Error have seen a statistically significant decrease in frequency (see **Figure 4.25**). For transformers there was an apparent increase in operational and total forced outages caused by human error, however it was not statistically significant (see **Figure 4.26**).

[64] Human Error: relative human factor performance that include any incorrect action traceable to employees and/or contractors to companies operating, maintaining, and/or assisting the Transmission Owner.

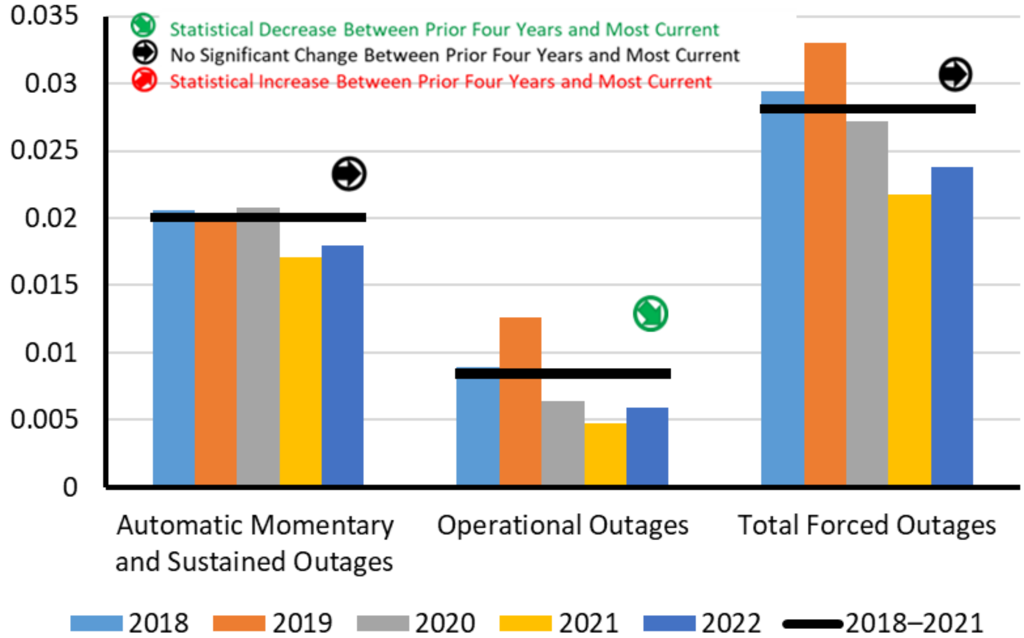


Figure 4.25: AC Circuit Outages per Circuit Initiated by Human Error

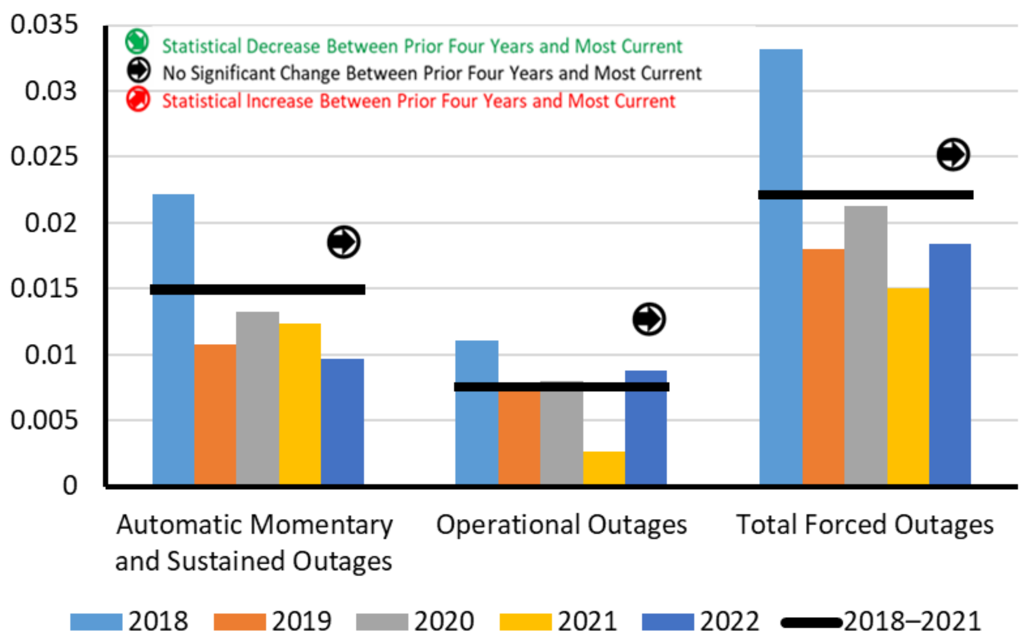


Figure 4.26: Transformer Outages per Element Initiated by Human Error

Generation Outages

NERC GADS collects generation outage data associated with a variety of causes that include Human Error. Over the past five years, forced outages attributed to Human Error have averaged around 1% of all forced generator outage events, and no fuel type showed a notable increase in 2022.

Trends of Events Root Causes

In the ERO EAP, the cause sets of individual human performance and management/organization identify events or conditions that are directly traceable to individual or management actions or organization methods (or lack thereof) that caused or contributed to the reported event. In 2022, organization/human performance was identified as the root cause for 20 processed events (see **Figure 4.27**). This is lower than for the previous years but may not fully project the final number as more than half of the 2022 events have not yet had a final root cause assigned to them. For the same period, the top five detailed root causes, listed in priority order, below are members of the management or organization performance categories:

1. Design output scope less than adequate
2. Job scoping did not identify special circumstances and/or conditions
3. Design output scope not correct
4. Previous industry or in-house experience was not effectively used to prevent recurrence
5. Corrective action responses to a known or repetitive problem were untimely

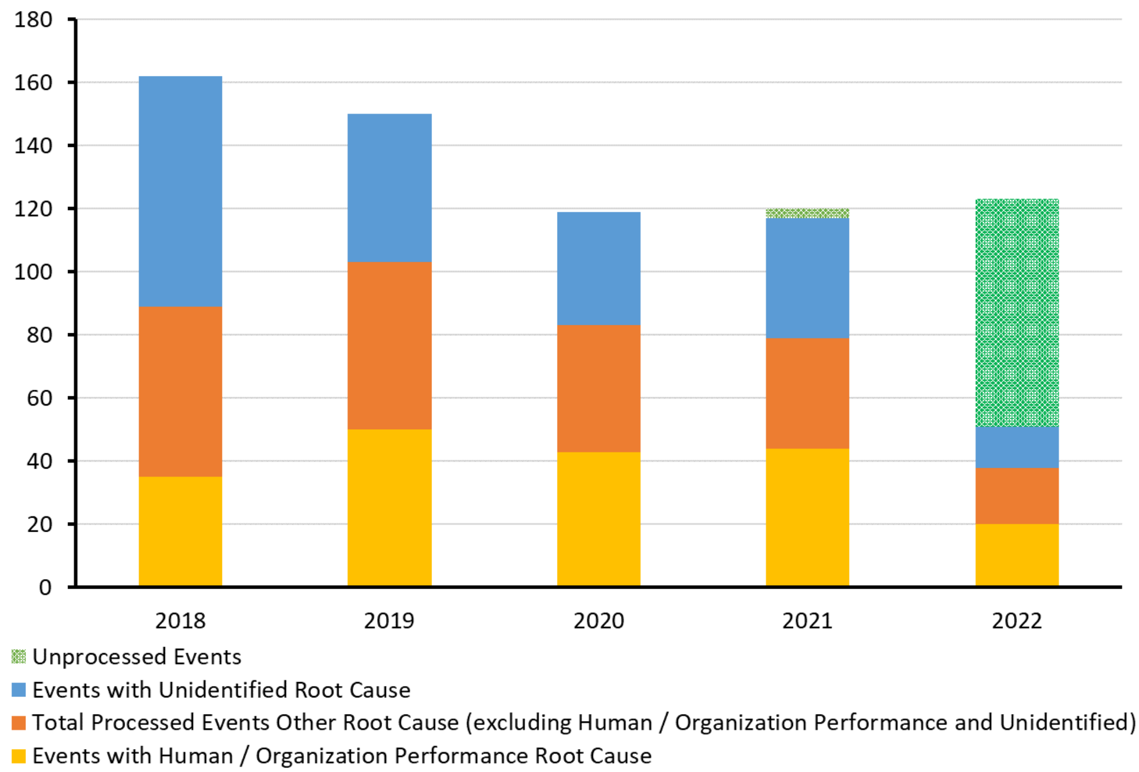


Figure 4.27: Organization/Human Performance Root Cause by Year

Events processed during 2022 saw three of the same top five root causes identified in 2021. Two causes—"Management policy guidance or expectations are not well-defined, understood, and/or enforced" and "System interactions not considered or identified"—were replaced with "Design output scope not correct" and "Previous industry or in-house experience was not effectively used to prevent recurrence."

The top five detailed root causes coupled with the apparent underlying increase suggests that an opportunity exists for industry to improve BPS reliability through increased focus in the area of management and organization performance and engineering design. Possible contributing and root causes in the area of management and organization performance include subcategories where methods, actions, and/or practices are less than adequate, such as management methods, resource management, work organization and planning, supervisory methods, and change management. Possible contributing and root causes in the area of engineering and design include ensuring that the engineering group has a robust peer review process to identify procedural errors and all considerations a design needs to be accountable to contain.

Human Error and Protection System Misoperations

Protection system misoperations remain an important indicator of the reliability of the BPS; Human Error is one of the potential causes for misoperations to occur. Figure 4.28 shows the number of misoperations due to Human Error by Regional Entity for the past five years. There are several different causes of Human Error misoperations reported in MIDAS: As-left Personnel Errors, Incorrect Settings, Logic Errors, and Design Errors. Together, these account for roughly 40% of misoperations over the last five years, described in more detail as follows:

- **As-left Personnel Errors:** These misoperations are due to the as-left condition of the composite protection system following maintenance or construction procedures. These include test switches left open, wiring errors not associated with incorrect drawings, carrier grounds left in place, settings placed in the wrong relay, or settings left in the relay that do not match engineering intended and approved settings. This includes personnel activation of an incorrect settings group.
- **Incorrect Settings:** These are errors in issued settings associated with electromechanical or solid-state relays, the protection element settings in microprocessor-based relays, and setting errors caused by inaccurate modeling. It excludes logic errors discussed in the Logic Error cause code.
- **Logic Errors:** This includes errors in issued logic settings and errors associated with programming microprocessor relay inputs, outputs, custom user logic, or protection function mapping to communication or physical output points.
- **Design Errors:** This involves incorrect physical design. Examples include incorrect configuration on ac or dc schematics or wiring drawings or incorrectly applied protective equipment.

Figure 4.28 indicates the number of misoperations varying among Regional Entities. The five-year trends generally show a stable or downward trend in misoperations with causes attributed to Human Error.

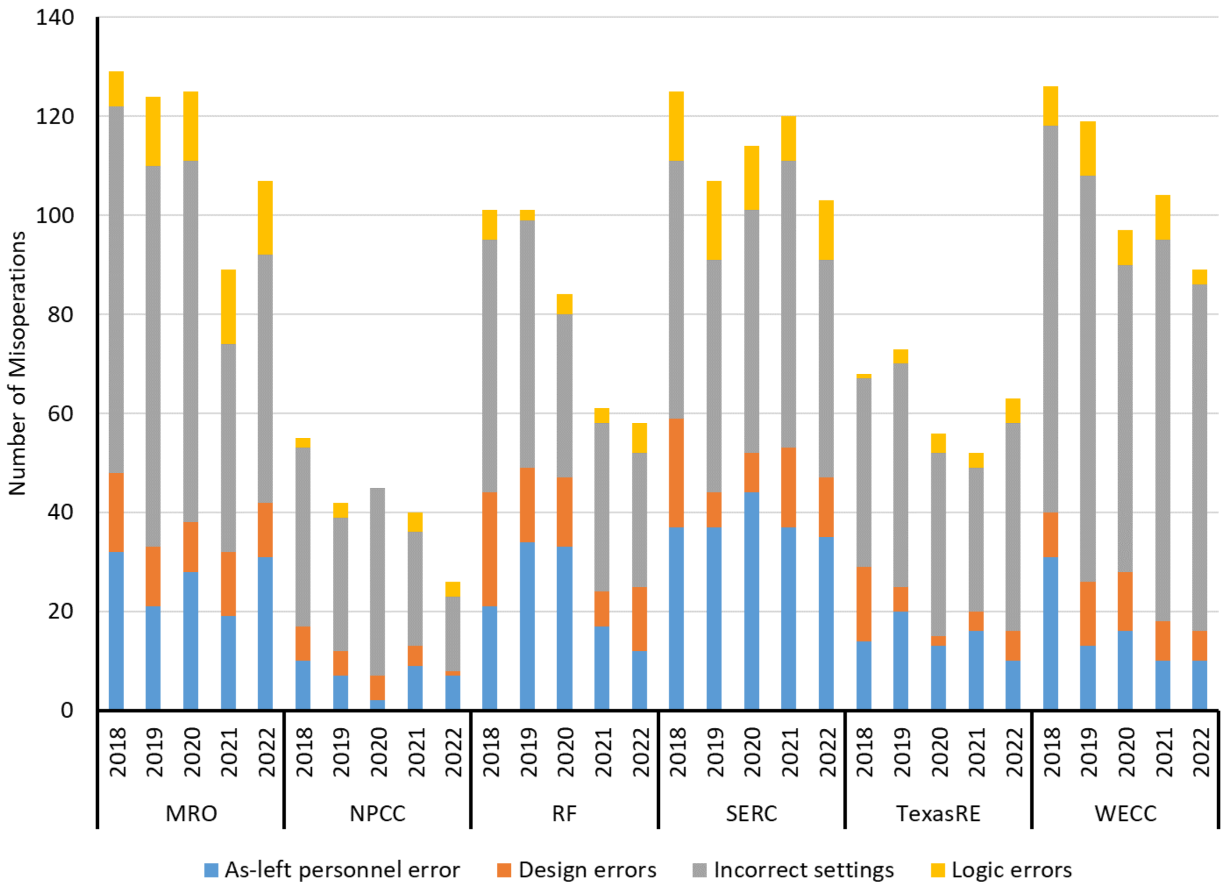


Figure 4.28: MIDAS Protection System Misoperations Due to Human Error by Regional Entity

Cyber and Physical Security

Threat Landscape Overview

Cyber and physical security continue to be a critical reliability element of the BPS. In 2022, the electric grid faced a multitude of security-related challenges that had potential to threaten reliable operation of the BPS. However, the BPS remained resilient with none of the incidents impacting overall BPS reliability, despite a number of high-profile distribution outages resulting from physical security attacks. The E-ISAC received eight CIP-008-6 reports of Cyber Security Incidents or attempts to compromise, which resulted in no customer outages or threats to BPS reliability.

Heightened awareness of security threats underscores the need for responsive cyber and physical mitigations to ensure reliability in the face of the existing security environment. In response to the invasion of Ukraine by Russia in February 2022 and Russia's resulting threats to nations supporting Ukraine, the Nation's Cybersecurity & Infrastructure Security Agency (CISA) launched the Shields Up! campaign. Additionally, NERC issued a Level 2 EEA to increase industry vigilance and to ensure all registered entities were aware of the Shields Up recommendations. Physical attacks in the fall and winter on grid infrastructure showed domestic extremists within our own borders sought to damage electrical infrastructure and undermine the reliable delivery of power to end-use customers.

In 2022, the E-ISAC shared 230 tailored analytic products, conducted 90 intelligence briefings, and shared 870 individual information posts on relevant cyber and physical threats to industry (see **Figure 4.29**). These tailored products covered a variety of threats, including cyber activity adjacent to the Russia-Ukraine war, the emergence of new destructive Operational Technology (OT) malware, significant increases in software vulnerabilities, ransomware compromises of utilities and vendors, and physical attacks on substations. Voluntary and mandatory sharing of information continues to be vital in assisting grid defenders and government partners in the United States and Canada monitor for threats and hold adversaries accountable.

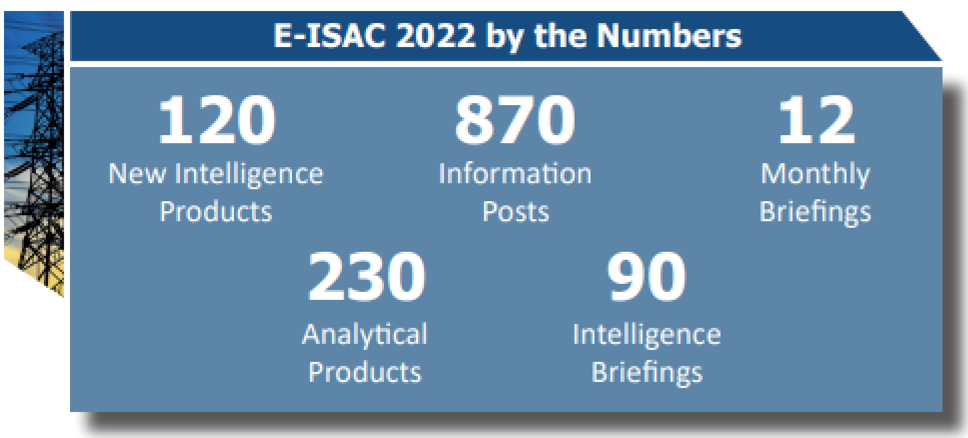


Figure 4.29: E-ISAC by the Numbers 2022

Physical Security

Throughout 2022, the E-ISAC observed an increase in physical security incidents that resulted in some level of impact on the grid in comparison to previous years (see **Figure 4.30**). The E-ISAC assesses physical security incidents based on their impact or potential to impact the reliability of the grid utilizing a Severity Level Categorization Model.[65] From September through December of 2022, there was a significant increase in the number of serious physical security incidents tracked by the E-ISAC. In November and December, a series of high-profile attacks on substations in the Pacific Northwest and Southeast United States included vandalism, tampering, arson, and ballistic damage. While there was no impact to the BPS as a result of these incidents, local power disruptions did occur, impacting tens of thousands of customers.

[65] The severity level categorization is adapted from a model that the Royal Canadian Mounted Police uses to assess incidents and has been adapted for electric industry use.

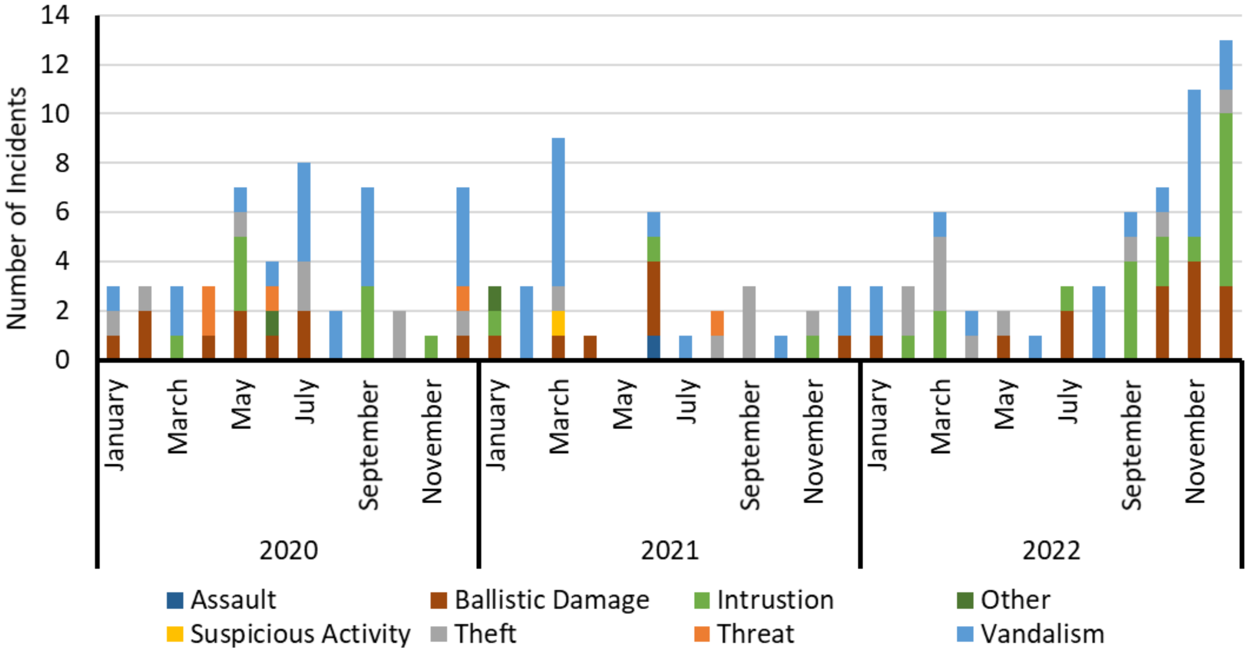


Figure 4.30: Level 2 and Level 3 Breakdown of Incident Types for 2020–2022

Concerns regarding growing physical security threats to the BPS led FERC to issue an order that directed NERC to assess the effectiveness of Reliability Standard CIP-014-3, focusing specifically on the inclusion applicability criteria, associated risk assessments, and whether a minimum level of physical security protections should be established for all BPS transmission stations, substations, and primary control centers.[66]

In addition, the E-ISAC actively exchanged information with government and industry partners about potential threats from domestic violent extremists (DVEs). The E-ISAC publishes a monthly report regarding online physical threats that highlights the more significant online discourse and potential aspirational threats targeting electricity infrastructure. [67] However, while rhetoric from extremist groups has been prevalent at this time, the actual motives and suspects for these attacks are not known.

In addition, the potential use of drones to conduct surveillance, espionage, and physical attacks that damage electrical infrastructure also remained a concern. The E-ISAC provided key findings and analysis of drone activity data gathered in late 2022 and is currently conducting a 12-month pilot to provide asset owners and operators with a baseline understanding of the level of drone activity around electric infrastructure. Analysis related to this effort will be shared through the E-ISAC Portal[68] in 2023.

Drones

Cyber Security

While there were no customer or BPS outages related to cyber attacks, NERC received eight CIP-008-6 reports Cyber Security Incidents or attempts to compromise in 2022. None of the incidents or attempts successfully compromised BES Cyber Systems or affected reliable operations of the BPS or distribution systems. NERC remains encouraged that there were no operational impacts and that the entities reported these attempts to the E-ISAC. It also recognizes this represents a very small fraction of cyber activity against industry.

The proliferation of new software vulnerabilities enabled geopolitical and criminal actors to conduct a number of ransomware, malware, distributed denial of service, credential harvesting (phishing) attempts, reconnaissance, and scanning attacks against computer networks. Several attacks or attempts targeted BES Cyber Systems like electronic

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[66] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20221215-3068&optimized=false
[67] E-ISAC Monthly Report: Online Physical Threats - February 2023
[68] https://www.eisac.com/s/

or physical access controls and monitoring systems, highlight the need for vigilance. Compromise of trusted third party vendors also presented as significant risk to industry as adversaries either exfiltrated sensitive information from engineering, equipment and construction firms used by industry, or sought to compromise software and/or hardware deployed by the vendors.

Cyber Vulnerabilities

In order to cause effects in a network, an adversary must first gain access. The most common attack vector is through the exploitation of software vulnerabilities in unpatched systems. The number of known vulnerabilities within information technology (IT) and OT networks and equipment continued to grow, including in the electricity industry. These vulnerabilities also manifested in the equipment specifically designed to protect these OT networks and systems. The number of entries in the CISA Known Exploited Vulnerabilities Catalog[69] likewise continued to climb in 2022. All adversaries, whether nation-states or ransomware groups, rely on unpatched systems and legacy vulnerabilities to gain initial access. The Apache Log4j vulnerability impact continued into 2022 and highlighted the need for patching and showed the magnitude and impact a common vulnerability can have. With IT serving a likely entry point to enterprise and potential OT networks, vulnerability management should remain an area of focus.

As grid transformation necessitates more ubiquitous networking, changes in grid architectures, robust vulnerability management programs for OT environments must keep pace. **Figure 4.31** shows the numerical trends, numbers, and the severity of vulnerabilities as reported through the National Institute of Standards and Technology national vulnerability database.[70] The low, medium, and high classifications are based on the Common Vulnerability Scoring System v2 base score. This data clearly shows that the number vulnerabilities continues to grow and industry must continue implementing effective cyber hygiene.

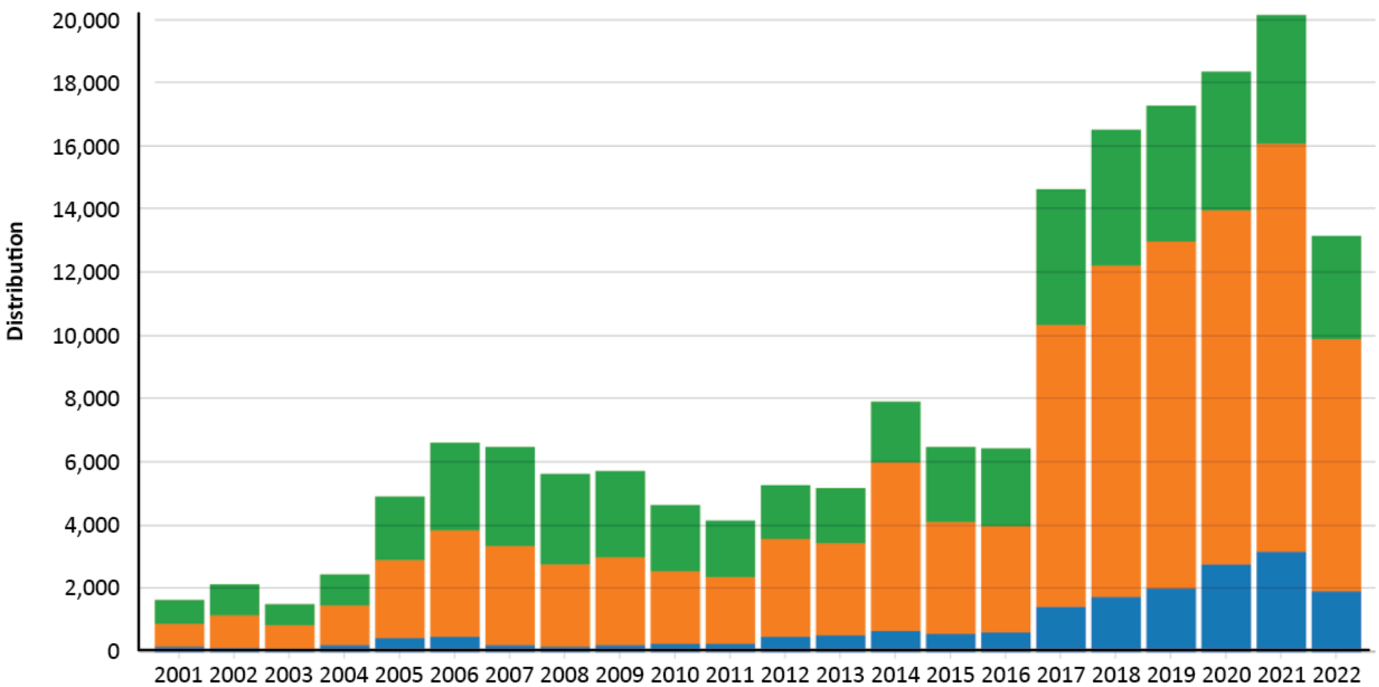

Figure 4.31: Number and Severity of Vulnerabilities 2001–2022[71]

[69] https://www.cisa.gov/known-exploited-vulnerabilities-catalog
[70] NIST Visualizations - Vulnerability-Distribution-Over-Time
[71] https://nvd.nist.gov/general/visualizations/vulnerability-visualizations/cvss-severity-distribution-over-time

OT Malware Threat

The evolution of cyber threats also presented new challenges to IT and OT network defenders. The year 2022 saw the release of a targeted industrial control system (ICS) specific attack toolkit. That toolkit, known as Pipedream (Dragos) or Incontroller (Mandiant),[72] facilitates adversaries' ability to attack OT equipment from well-known electricity industry manufacturers. While the toolkit did not lead to an attack or outages, its existence highlights the risk to OT environments for industry. Similarly, the Ukrainian energy authority foiled an attempt by Russian-linked actors to deploy the Industroyer2 malware in its high-voltage substations in the spring of 2022. Other notable global cyber events included attacks on European wind turbine companies that resulted in a loss of availability to IT systems and malware that successfully exploited virtual infrastructure hypervisors that are widely used in energy IT and OT systems.

In OT cyber security, networks with no internal visibility are difficult to protect. Following the White House 100 Day ICS Cybersecurity Spring initiative in 2021, FERC issued an internal network security monitoring (INSM) notice of proposed rulemaking[73] in January 2022 that directed NERC to develop new or modified CIP Reliability Standards to require INSM for all high impact and some medium impact BES cyber systems. Furthermore, NERC's ongoing actions resulting from the notice of proposed rulemaking and subsequent order 887[74] include conducting a study to determine the feasibility of future INSM requirements for the remaining medium impact and all low impact BES cyber systems.

Ransomware

Ransomware continued to impact the industry and key vendor suppliers. While financial gain is often the primary motive of the transnational ransomware gangs, several of these groups may also operate with the tacit support of nation-state adversaries like Russia and China. In 2022, the FBI received over 800 ransomware criminal complaints from critical infrastructure operators; this included 15 from energy sector entities like electricity asset owners and operators (see **Figure 4.32**). The top ransomware variants included LockBit, ALPHV/BlackCat, and Hive. Ransomware gangs also targeted trusted third-party electricity contractors like engineering firms, construction services, and original equipment manufacturers. The E-ISAC provided awareness of these events to industry through all-points bulletins and other cyber bulletins to raise awareness and encourage entities to evaluate their risk.

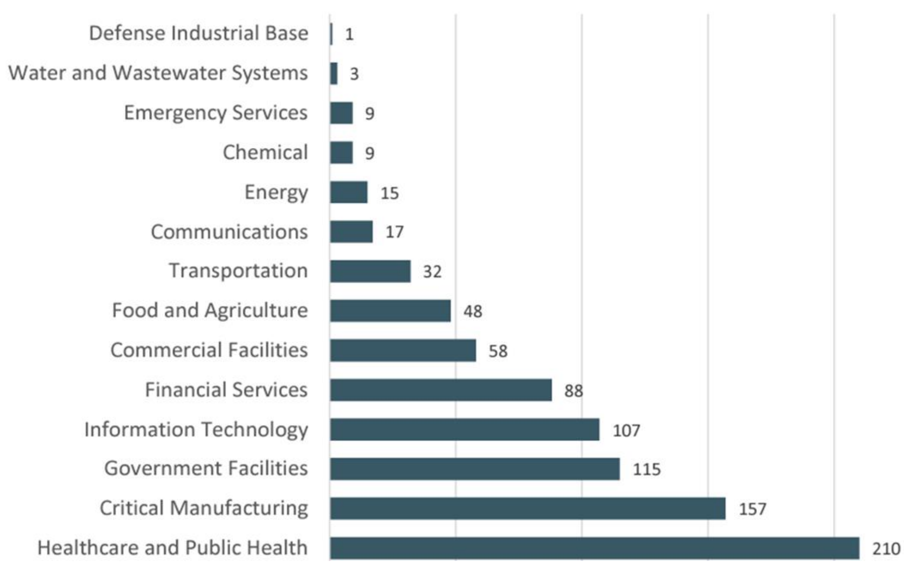

Figure 4.32: Infrastructure Sectors Victimized by Ransomware 2022[75]

[72] Pipedream (Dragos) or Incontroller (Mandiant)

[73] Internal Network Security Monitoring for High and Medium Impact Bulk Electric System Cyber Systems, Notice of Proposed Rulemaking, 178 FERC ¶ 61,038 (2022)

[74] Internal Network Security Monitoring for High and Medium Impact Bulk Electric System Cyber Systems, Order No. 887, 182 FERC ¶ 61,021 (2023)

[75] FBI, 2022 Internet Crime Report – Ransomware: *https://www.ic3.gov/Media/PDF/AnnualReport/2022_IC3Report.pdf*

While there were no impacts on BPS reliability from these events, the continued targeting of critical infrastructure and the development of ransomware code to target industrial and OT environments highlighted the need for continued diligence. The E-ISAC, in collaboration with industry and government experts, developed *ICS "Shields Up" Considerations for the Electricity Industry*[76] notice for its members to assist entities in improving their response to OT malware and ransomware threats. CISA also began a *#StopRansomware Campaign*[77] to assist businesses and infrastructure operators of all sizes in preparing for these types of attacks.

Looking Forward

Grid transformation efforts continue while generation resources continue to shift to higher penetrations of IBRs and distributed energy resources connected to distribution systems. The communication networks and equipment—smart devices required to manage these systems, large data sets and the required analysis of that data—all lead to an increased attack surface for the networks required to manage and maintain grid reliability. The electricity industry, like most others, will continue to face these cyber and physical threats now and into the future. New systems and applications that manage distributed energy resources require security integration at every level of planning, design, implementation, and operation in order to maintain BPS reliability and position industry on a strong security footing.

Understanding cyber and physical security threats through coordinated and timely threat intelligence sharing and mitigating the risks posed by these threats through implementing robust security integration strategies[78] is paramount to reducing risks and defending the reliability of the BPS. The E-ISAC is working closely with CISA through the Joint Cyber Defense Collaborative, the U.S. Department of Energy's Energy Threat Analysis Center pilot, and the Canadian Centre for Cybersecurity to improve the operational coordination of intelligence on behalf of the industry. Industry advisory groups—like the Electricity Subsector Coordinating Council, the E-ISAC's Physical Security Advisory Group, and the Cybersecurity Advisory Group—play a critical role providing asset owners and operators input and context to support the U.S. and Canadian governments' collective defensive efforts.

Industry cyber security practices should go beyond the minimum levels specified in the NERC CIP Standards. Strong multifactor authentication for all remote access and malicious code detection at all facilities is prudent due to the nature of the constantly changing threat environment. These threats and the risks they pose to the Nation's critical infrastructure are manifested in the release of the White House's multi-pillar 2023 National Cybersecurity Strategy.[79] The strategy highlights a vision of increased collaboration between government and private sectors, a move toward streamlined incident reporting, threat intelligence dissemination, and efforts to disrupt criminal and nation-state efforts to attack the nation's critical infrastructure.

[76] TLP Green Limited disclosure, restricted to the community
[77] CISA, "Stop Ransomware" - https://www.cisa.gov/stopransomware
[78] SecurityIntegrationStrategy_07DEC22.pdf (nerc.com)
[79] National Cybersecurity Strategy

Chapter 5: Adequate Level of Reliability Performance Objectives

Adequate level of reliability (ALR) is the state that the design, planning, and operation of the BES will achieve when the listed reliability performance objectives (RPO) are met (*See Informational Filing on the Definition of "Adequate Level of Reliability*").[80] The ALR's RPOs articulate what system planners and operators are expected to do on a day-to-day basis to ensure that the BES is reliable; these represent the bottom-line performance objectives that the NERC Performance Analysis Subcommittee and the NERC reliability assessment staff have reported on throughout this SOR report.

This chapter reorganizes the individual findings presented in the preceding chapters to provide a final integrated summary of BES reliability that is directly aligned with each of the five ALR RPO (see **Table 5.1**) so that they can be tracked consistently over time. Reliability metrics[81] M4, M6, M8, M9, M11–M15, and M17 are calculated annually and employed in **Table 5.1** for this purpose. Where appropriate, the year-over-year and rolling five-year trend for each metric is color coded for each of the Interconnections (Eastern, Québec, Texas, and Western Interconnections) as well as the relevant transmission element (ac circuits and transformers). Except to identify gaps in data that must be addressed in future SORs, this chapter does not seek to add to the narratives presented earlier but instead simply summarizes overall findings with respect to the ALR RPOs.

In reviewing **Table 5.1**, it is important to bear in mind that RPO 1–3 are defined with respect to more probable predefined disturbances, which are the ones the BES is planned, designed, and operated to withstand. In contrast, RPO 4 and 5 cannot be defined with respect to more probable disturbances.

Table 5.1: Adequate Level of Reliability Performance Objectives

Reliability Performance Objectives	Improving	Stable	Monitor	Actionable
1. The BES does not experience instability, uncontrolled separation, cascading, or voltage collapse	• Western Interconnection IROL Exceedances (M-8) • Texas Interconnection IROL Exceedances (M-8) • Automatic ac circuit outages initiated by Failed ac Substation Equipment (M-14) • Automatic ac transmission outages initiated by Failed ac Circuit Equipment (M-15) • Transmission Outage Severity (M-17)	• Eastern and Québec Interconnections IROL Exceedances (M-8)	• Automatic transformer outages initiated by Failed ac Substation Equipment (M-14) • Disturbance Control Standard (M-6)	
2. BES frequency is maintained within defined parameters.	• Texas Interconnection frequency response A to B (M-4)	• Eastern, Québec, and Western Interconnections frequency		

[80] Informational Filing on Definition of "Adequate Level of Reliability," May 10, 2013.
[81] Reliability metrics: https://www.nerc.com/comm/PC/Pages/Performance-Analysis-Subcommittee-(PAS)-2013.aspx

Table 5.1: Adequate Level of Reliability Performance Objectives				
Reliability Performance Objectives	**Improving**	**Stable**	**Monitor**	**Actionable**
	• Texas Interconnection frequency response A to C (M-4)	response A to B (M-4) • Eastern, Québec, and Western Interconnections frequency response A to C (M-4)		
3. BES voltage is maintained within defined parameters.	N/A			
4. Adverse Reliability Impacts on the BES following low probability disturbances are managed.	• Texas and Western Interconnections IROL Exceedances (M-8) • Automatic transformer outages initiated by Failed Protection System Equipment (M-12) • Protection system Misoperation rate (M-9) • Québec and Texas Interconnections EEAs (M-11)	• Eastern-Québec Interconnections IROL Exceedances (M-8) • Automatic ac circuit outages initiated by Failed Protection System Equipment (M-12) • Automatic transformer outages initiated by Human Error (M-13)	• Automatic ac circuit outages initiated by Human Error (M-13) • Eastern and Western Interconnections EEAs (M-11) • Disturbance Control Standard (M-6)	
5. Restoration of the BES after major system disturbances is performed in a coordinated and controlled manner.		• BES transmission system restoration		

For these less probable events, yet routinely severe, BES owners and operators may not be able to apply any economically justifiable or practical measures to prevent or mitigate their adverse reliability impacts (ARI)[82] on the BES despite the fact that these events can result in cascading, uncontrolled separation, or voltage collapse. For this reason, these events generally fall outside of the design and operating criteria for BES owners and operators. Less probable severe events would include, for example, losing an entire right-of-way due to a tornado or multiple transmission facility outages occurring near simultaneously due to a hurricane or other severe natural phenomena.

Under normal operating conditions and during the occurrence of predefined disturbances (i.e., more probable disturbances to which the power system is planned, designed, and operated to handle), the BES in 2022 experienced

[82] The impact of an event that results in frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection: https://www.nerc.com/files/glossary_of_terms.pdf

no instability, uncontrolled separation, cascading, or voltage collapse. Moreover, BES frequency and voltage were maintained within defined parameters during these operating conditions in 2022. Frequency response analysis in both the arresting period and stabilizing period indicates Stable or Improving performance for all of the Interconnections as metrics M-4, Interconnection frequency response A to B, and M-4.1, Interconnection frequency response A to C (see **Table 5.1)**. Specific metrics to assess BES voltage performance have not yet been developed.

In 2022, the BES was subjected to a number of less probable and severe events as evidenced by the extreme day SRI discussed in **Chapter 2** and further expanded upon in **Appendix A**. In every instance, ARI[83] were avoided and ALR maintained through operator actions as documented through actions taken pursuant to EEA Level 3. Furthermore, restoration of the BES was conducted in a controlled and coordinated manner compared to similar historical events, for example, in the **Chapter 2** BES element restoration curves developed for Hurricane Ian. While ALR was maintained in 2022, the reliability indicators shown in **Table 5.1** that fall within the Monitor category highlight areas of continuing concern that underlie many of the recommendations provided in this report. Improvement in these metrics and measures would likely reflect a decreased severity of low probability disturbances as well as enhanced BES resiliency during and accelerated BES restoration after major system disturbances.

In addition to refining and developing restoration and resiliency metrics to include load restoration, annual evaluation of the past year's BES performance in providing an ALR would be significantly enhanced with the addition of energy resource adequacy and voltage metrics. Filling in the current gaps in **Table 5.1** will require NERC's Performance Analysis Subcommittee, ERO Enterprise reliability assessment staff, and industry to undertake development of load restoration definition and analysis as well as energy resource adequacy and voltage metrics.

Expanding Role of Data in Assessing BES Performance

In recent years, limitations on access to data that is necessary to conduct deeper analysis on the challenges the BES now faces, such as extreme weather, have become increasingly evident. Using this data to make prompt adjustments to conclusions, processes, and standards has highlighted the importance of a data governance focus throughout the data collection process. Alignment of data sources, clarity of data granularity, timeliness, modelling capabilities, precision with definitions, and the ability to correlate data across and within datasets has become increasingly critical. Strategic decisions require strong data governance processes to ensure that the right conclusions are being drawn from the data being assembled. Ideally, these datasets would be catalogued in detail with any identified weaknesses in plans for data quality improvements.

Revisions to the GADS Section 1600 that become effective in 2024 include additional wind and solar PV data as well as information to clearly indicate whether external operating conditions have contributed to a reported outage. NERC is also reviewing the other Section 1600 Data Requests in effect to better align them with current and future analytical needs. Areas currently under consideration include the following:

- BES load loss information
- IBR modelling capabilities
- Modelling data accuracy
- Transmission information to identify relation to weather events
- Daily peak generation capacity or demand information
- More quantifiable information regarding the severity of transmission outages and protection system misoperations

[83] The impact of an event that results in frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection: https://www.nerc.com/files/glossary_of_terms.pdf

Appendix A: Supplemental Analysis at Interconnection Level

Severity Risk Index by Interconnection

Eastern–Québec Interconnection

The cumulative SRI for the Eastern and Québec Interconnections in **Table A.1** shows a 4% increase compared to the average of the four-year period of 2018–2021. In the Eastern and Québec Interconnections, the 2021 cumulative SRI is the median among the five years (2018–2022); it is statistically significantly lower than 2018 but not statistically lower or higher than other years.

Table A.1: Annual Cumulative SRI Eastern and Québec Interconnections

Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2018	383.4	63.2	96.4	543.0	1.49
2019	345.9	59.6	51.2	456.7	1.25
2020	315.4	58.7	67.4	441.4	1.21
2021	346.2	54.8	57.5	458.5	1.26
2022	**385.3**	**53.3**	**53.0**	**491.6**	**1.35**

The top 10 SRI days of the Eastern and Québec Interconnections were distributed throughout the year as shown in **Figure A.1** (numbered circles)**.** A total of 7 of the top 10 days that occurred in the Eastern and Québec Interconnections contributed to the top 10 SRI days reported for North America. Winter Storm Elliott and the high temperature/derecho days account for 3 of the top 10 days each.

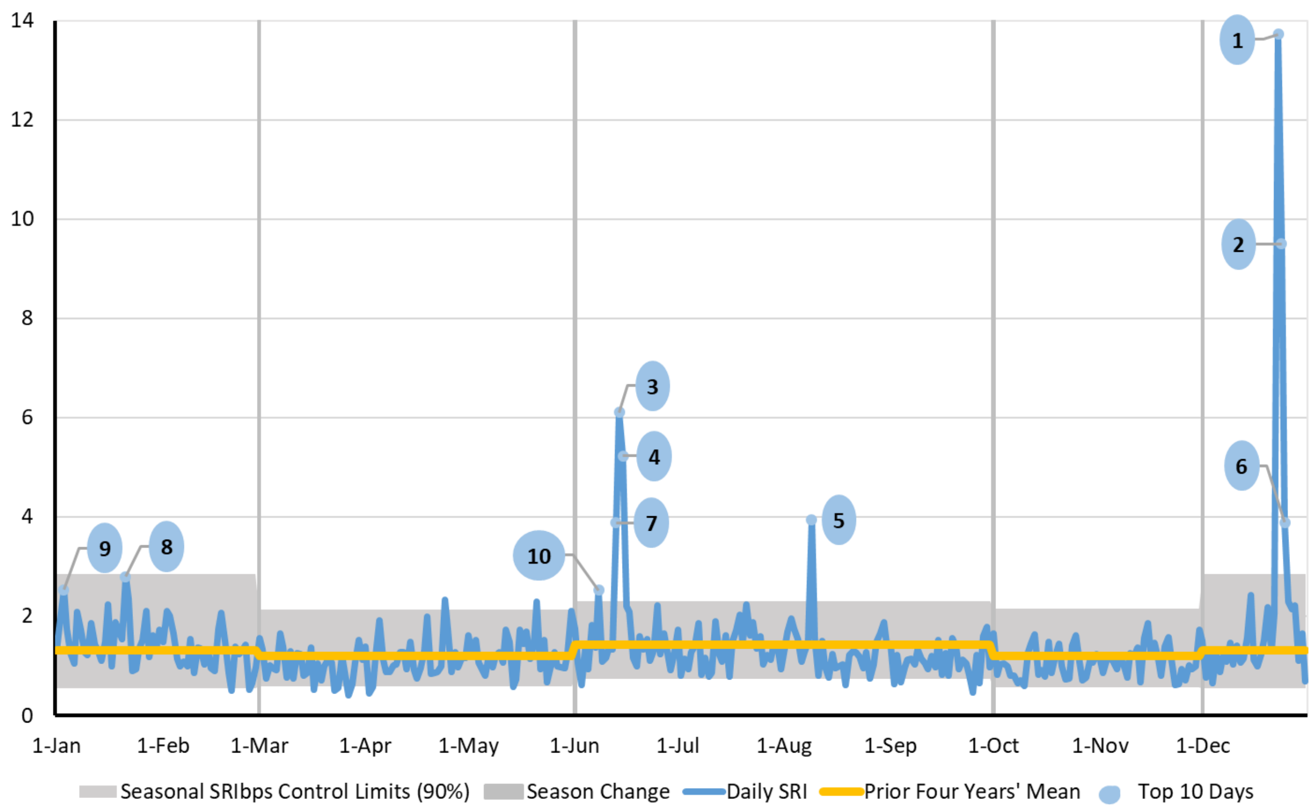

Figure A.1: 2022 Eastern and Québec Interconnections Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

When comparing the top 10 days in 2022 to each of the previous four years shown in **Figure A.2**, the year 2022 had the two worst overall days and was above average for the next four.

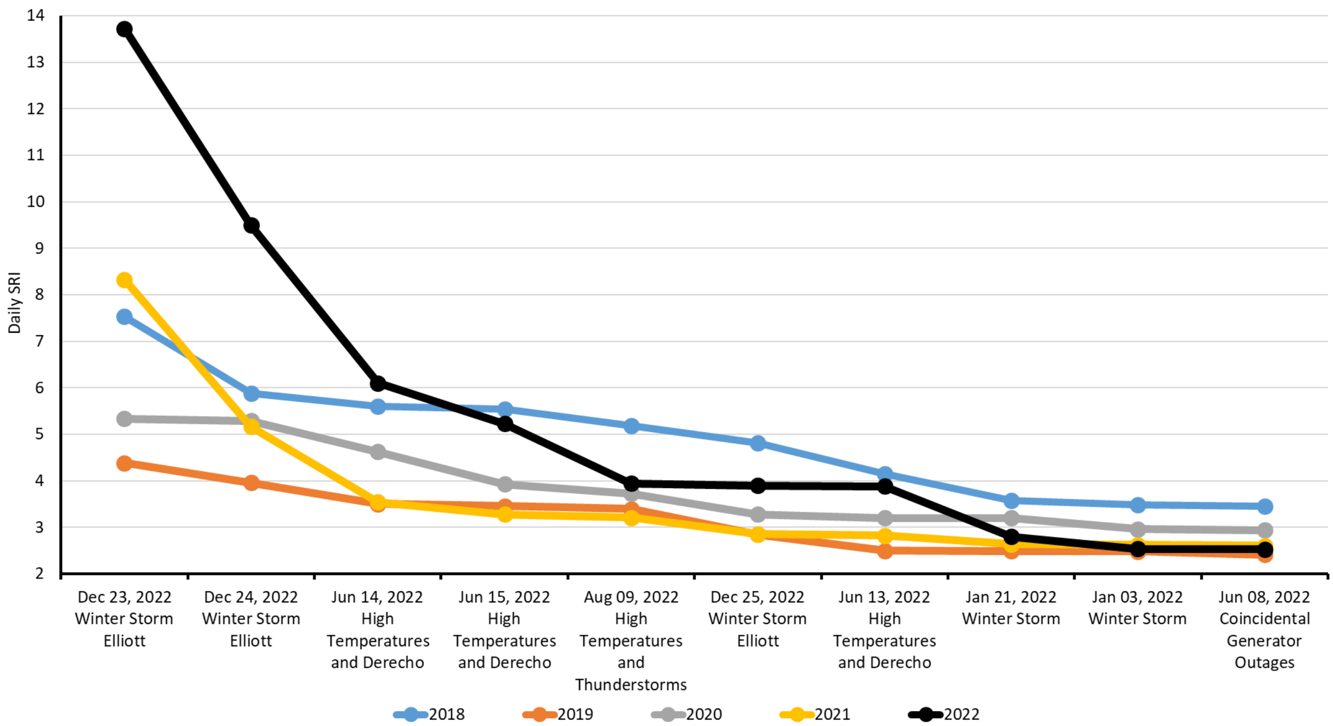

Figure A.2: Eastern and Québec Interconnections Top Annual Daily SRI Days, Sorted Descending

Table A.2 provides details on each component's contribution to the top 10 SRI days for the Eastern and Québec Interconnections. Generation loss was the primary contributor to 8 of the top 10 days.

Table A.2: 2022 Top 10 SRI Days Eastern and Québec Interconnections

Rank	Date	SRI and Weighted Components 2022				Atypical Weather Conditions	Regional Entities within the Interconnection
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	December 23	13.72	8.88	0.92	3.92	Winter Storm Elliott	All
2	December 24	9.50	8.13	1.30	0.07	Winter Storm Elliott	All
3	June 14	6.10	1.71	0.50	3.90	High Temperatures and Derecho	MRO, NPCC, RF, SERC, TRE
4	June 15	5.23	1.63	0.24	3.36	High Temperatures and Derecho	MRO, NPCC, RF, SERC, TRE
5	August 9	3.95	1.96	0.28	1.70	High Temperatures and Thunderstorms	All
6	December 25	3.90	3.80	0.09	0.00	Winter Storm Elliott	All

Table A.2: 2022 Top 10 SRI Days Eastern and Québec Interconnections							
Rank	Date	SRI and Weighted Components 2022				Atypical Weather Conditions	Regional Entities within the Interconnection
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
7	June 13	3.88	2.37	0.13	1.39	High Temperatures and Derecho	MRO, NPCC, RF, SERC, TRE
8	January 21	2.80	2.45	0.29	0.07	Winter Storm	MRO, RF, SERC
9	January 3	2.54	2.11	0.37	0.06	Winter Storm	RF
10	June 8	2.53	1.96	0.27	0.30	Coincidental Generator Outages	SERC

Three of the top 10 SRI days in 2022, shown in red in **Table A.3**, are included as historically high SRI days for the Eastern and Québec Interconnections.

Table A.3: 2018–2022 Top 10 SRI Days Eastern and Québec Interconnections							
Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entities within the Interconnection
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	December 23, 2022	13.72	8.88	0.92	3.92	Winter Storm Elliott	All
2	December 24, 2022	9.50	8.13	1.30	0.07	Winter Storm Elliott	All
3	February 16, 2021	8.33	4.11	0.59	3.63	Cold Weather Event	MRO, RF, SERC
4	September 14, 2018	7.53	1.62	0.54	5.37	Hurricane Florence	SERC
5	June 14, 2022	6.10	1.71	0.50	3.90	High Temperatures and Derecho	MRO, NPCC, RF, SERC, TRE
6	October 11, 2018	5.88	0.64	0.68	4.56	Hurricane Michael	SERC
7	April 15, 2018	5.61	0.93	0.48	4.19	Thunderstorms and winter storms	NPCC, SERC
8	November 15, 2018	5.54	1.82	0.21	3.52	Winter Storm Avery	NPCC, RF
9	August 4, 2020	5.34	1.38	1.03	2.93	Hurricane Isaias	NPCC, RF, SERC
10	August 27, 2020	5.28	1.42	1.34	2.52	Unnamed Tropical Storm	RF, SERC

Western Interconnection

The 2022 cumulative SRI for the Western Interconnection (see **Table A.4**) shows a 3% increase over the prior four-year period of 2018–2021. The 2022 cumulative SRI was the median among the five years analyzed and statistically significantly higher than 2018 and lower than 2021. In 2022 cumulative transmission was the lowest of all five years, load loss second lowest behind 2018, and generation the highest (see **Table A.4**).

Table A.4: Annual Cumulative SRI Western Interconnection

Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2018	395.9	104.1	41.0	541.0	1.48
2019	421.7	104.7	74.9	601.2	1.65
2020	390.8	100.8	71.9	563.5	1.54
2021	426.8	104.4	97.8	628.9	1.72
2022	**444.6**	**94.0**	**60.1**	**598.7**	**1.64**

The top 10 SRI days of the Western Interconnection for 2022 were primarily clustered in the winter months, with a few days just outside of the control limits occurring throughout the summer as shown in **Figure A.3**. All days were driven by either generation or load loss.

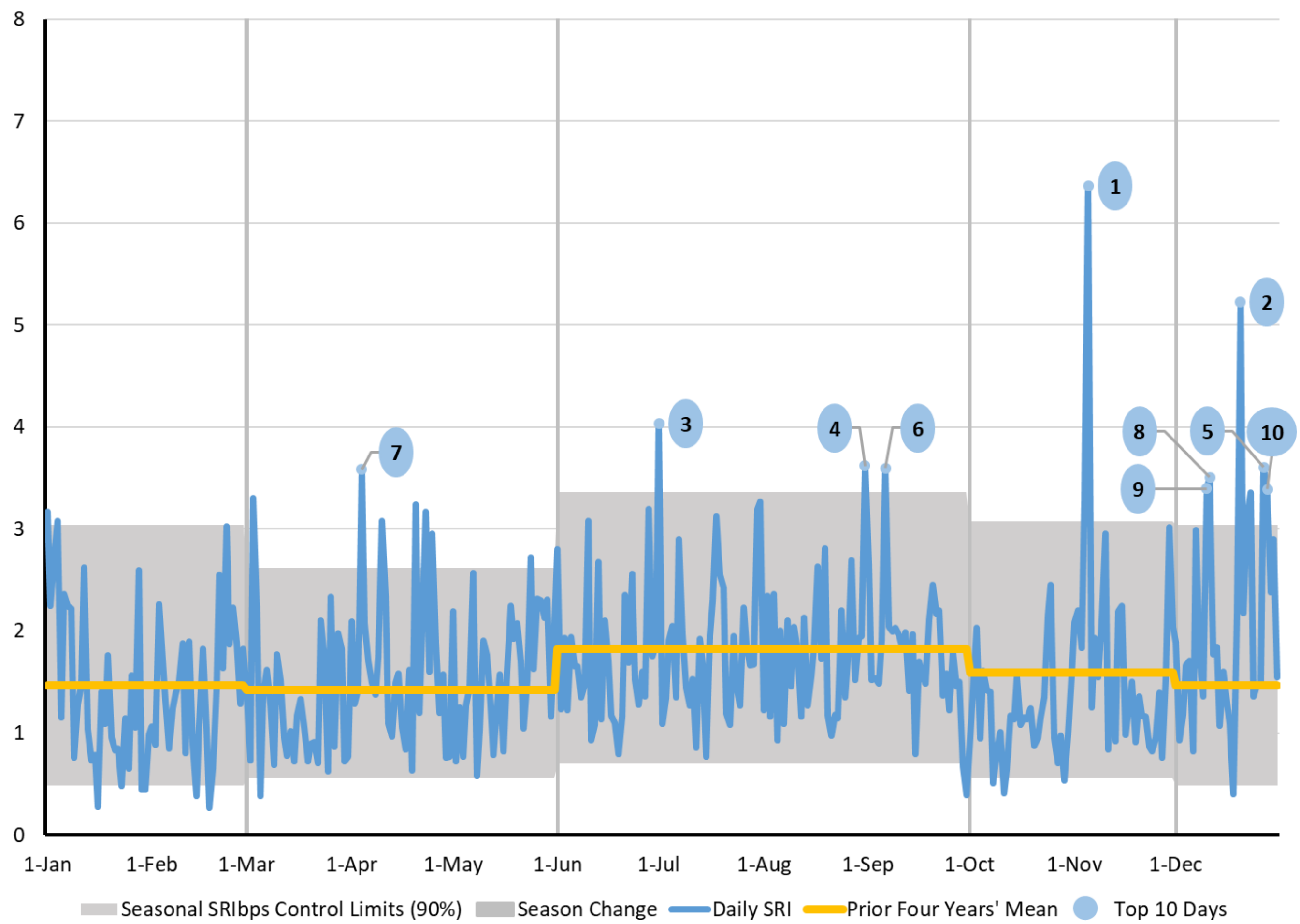

Figure A.3: 2022 Western Interconnection Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

When comparing the top 10 days in 2022 to each of the previous four years as shown in **Figure A.4**, most of the 2022 days were better than prior years.

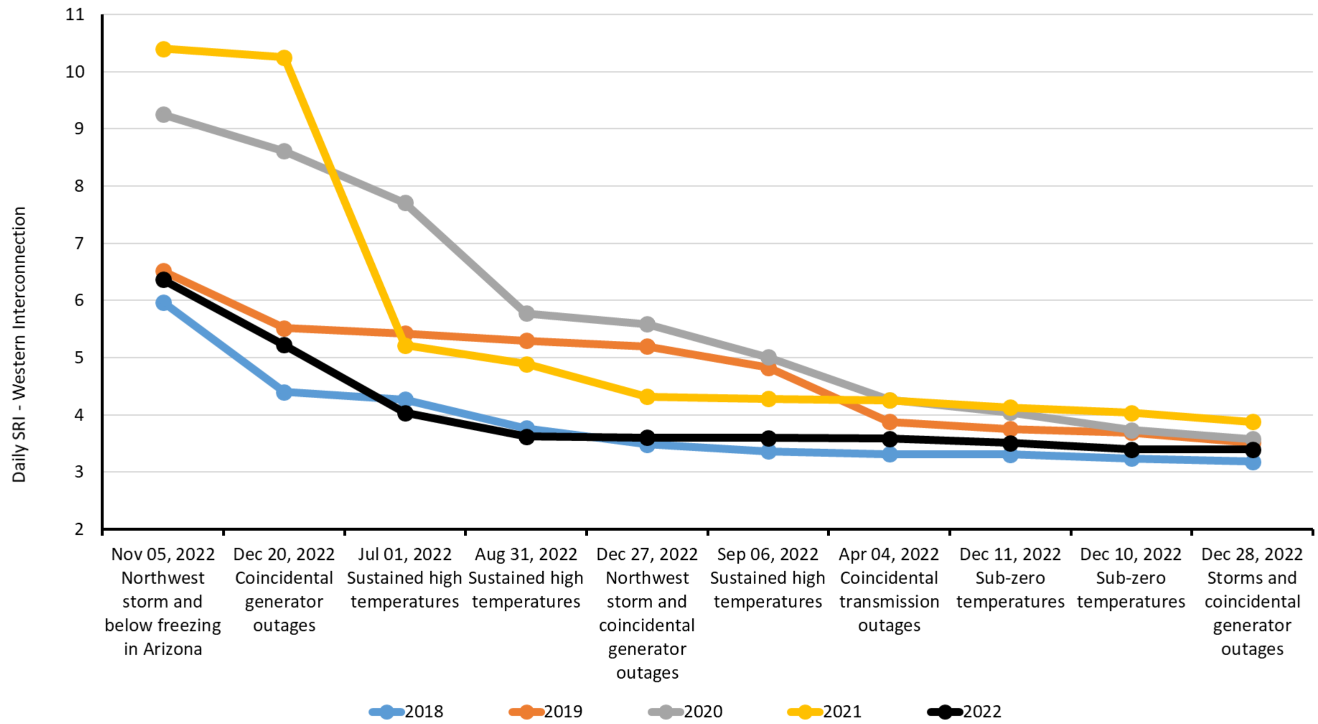

Figure A.4: WI Top Annual Daily SRI Days Sorted Descending

Table A.5 provides details on each component's contribution to the top 10 SRI days for the Western Interconnection; WECC is the only Regional Entity in the Western Interconnection.

Table A.5: 2022 Top 10 SRI Days Western Interconnection

Rank	Date	SRI and Weighted Components 2022				Atypical Weather Conditions
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
1	November 5	6.37	1.85	1.91	2.61	Northwest storm and below freezing in Arizona
2	December 20	5.23	1.13	0.17	3.93	Coincidental generator outages
3	July 1	4.04	2.93	0.99	0.11	Sustained high temperatures
4	August 31	3.62	2.55	0.90	0.17	Sustained high temperatures
5	December 27	3.61	1.26	1.17	1.18	Northwest storm and coincidental generator outages
6	September 6	3.60	2.80	0.10	0.70	Sustained high temperatures
7	April 4	3.59	0.79	1.18	1.62	Coincidental transmission outages
8	December 11	3.51	1.85	0.92	0.75	Sub-zero temperatures
9	December 10	3.40	1.05	0.65	1.70	Sub-zero temperatures
10	December 28	3.39	1.37	1.68	0.35	Storms and coincidental generator outages

One of the top 10 SRI days in 2022, shown in red in **Table A.6**, is included in the historically high SRI days for the Western Interconnection.

Table A.6: 2018–2022 Top 10 SRI Days Western Interconnection

Rank	Date	SRI and Weighted Components				Atypical Weather Conditions
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
1	January 13, 2021	10.41	1.86	4.07	4.48	Northwest winter weather
2	November 15, 2021	10.26	1.42	0.42	8.41	High winds and special protection system misoperation
3	September 8, 2020	9.25	3.38	3.15	2.73	Wild fires
4	September 7, 2020	8.61	2.51	2.33	3.78	Wild fires
5	August 14, 2020	7.71	1.29	0.00	6.43	Extreme heat
6	October 11, 2019	6.51	0.75	5.74	0.02	Saddle Ridge fire
7	November 5, 2022	6.37	1.85	1.91	2.61	Northwest storm and below freezing in Arizona
8	August 11, 2018	5.97	1.63	2.40	1.93	Natchez fire
9	August 15, 2020	5.77	0.99	0.23	4.55	Extreme heat
10	August 17, 2020	5.58	2.13	0.87	2.58	Extreme heat

Extreme Day Analysis by Interconnection

The extreme day analysis for transmission and generation for 2022 are presented by Interconnection. The maximum TADS reported MVA or GADS reported net maximum capacity for 2022 is shown in the upper right corner of **Figure A.5–Figure A.10**. The biggest outliers and extreme days correlating with NERC-wide extreme days have been labelled with any atypical weather conditions during those days. Lower-impacting extreme days without a distinctly listed cause have been investigated and were elevated above the threshold to coincidental outages or unnamed storms. All dates shown in UTC.

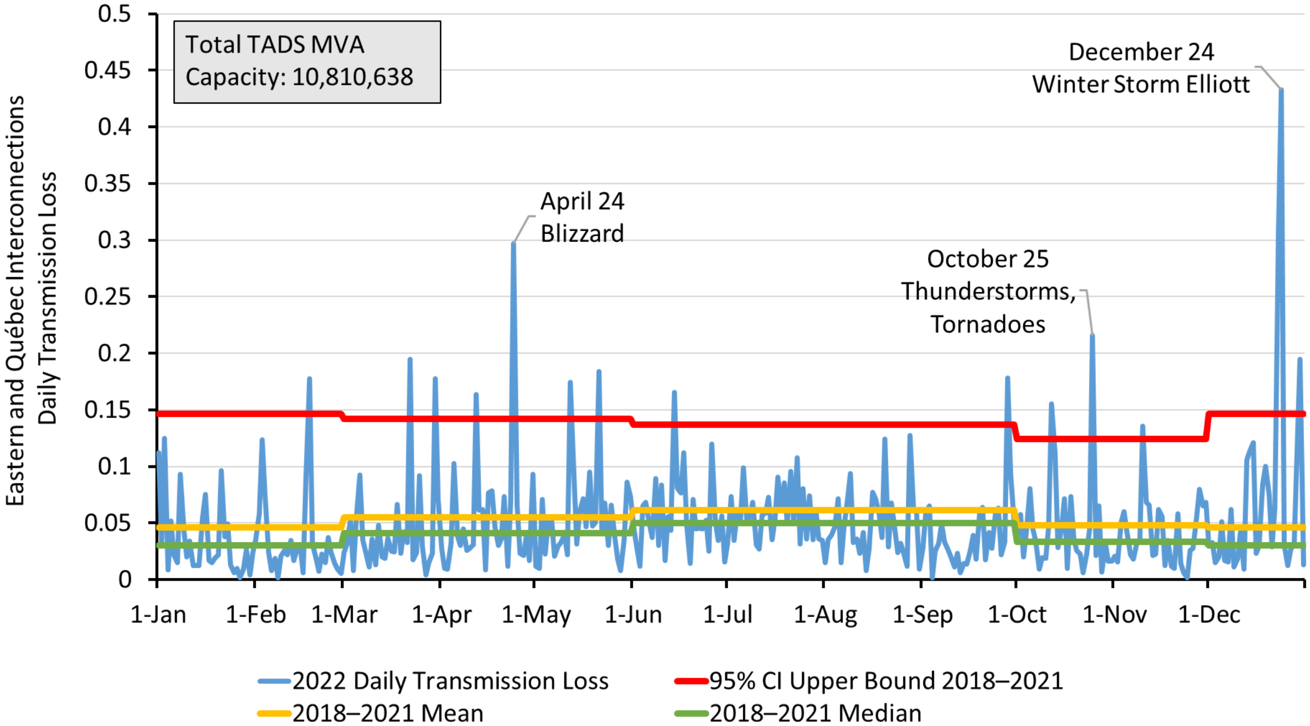

Figure A.5: Eastern and Québec Interconnections—Transmission Impacts during Extreme Days of 2022

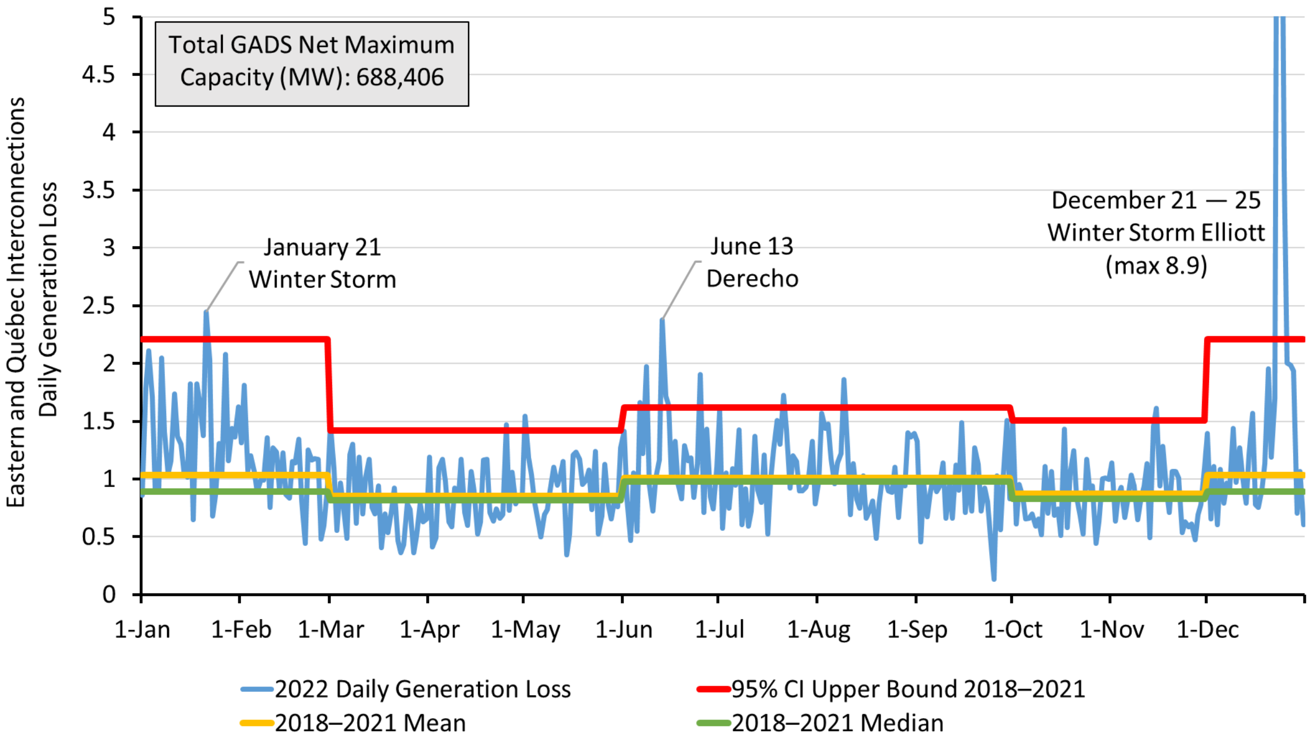

Figure A.6: Eastern and Québec Interconnections—Generation Impacts during Extreme Days of 2022

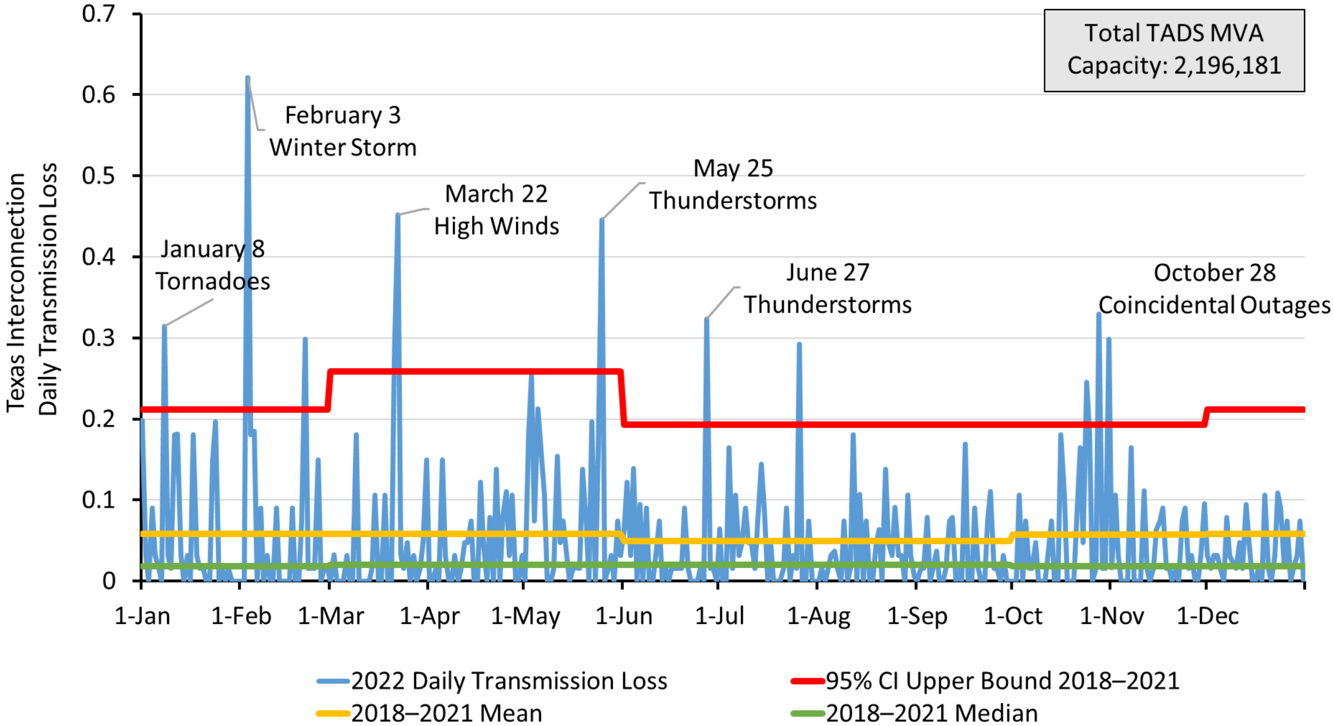

Figure A.7: Texas Interconnection—Transmission Impacts during Extreme Days of 2022

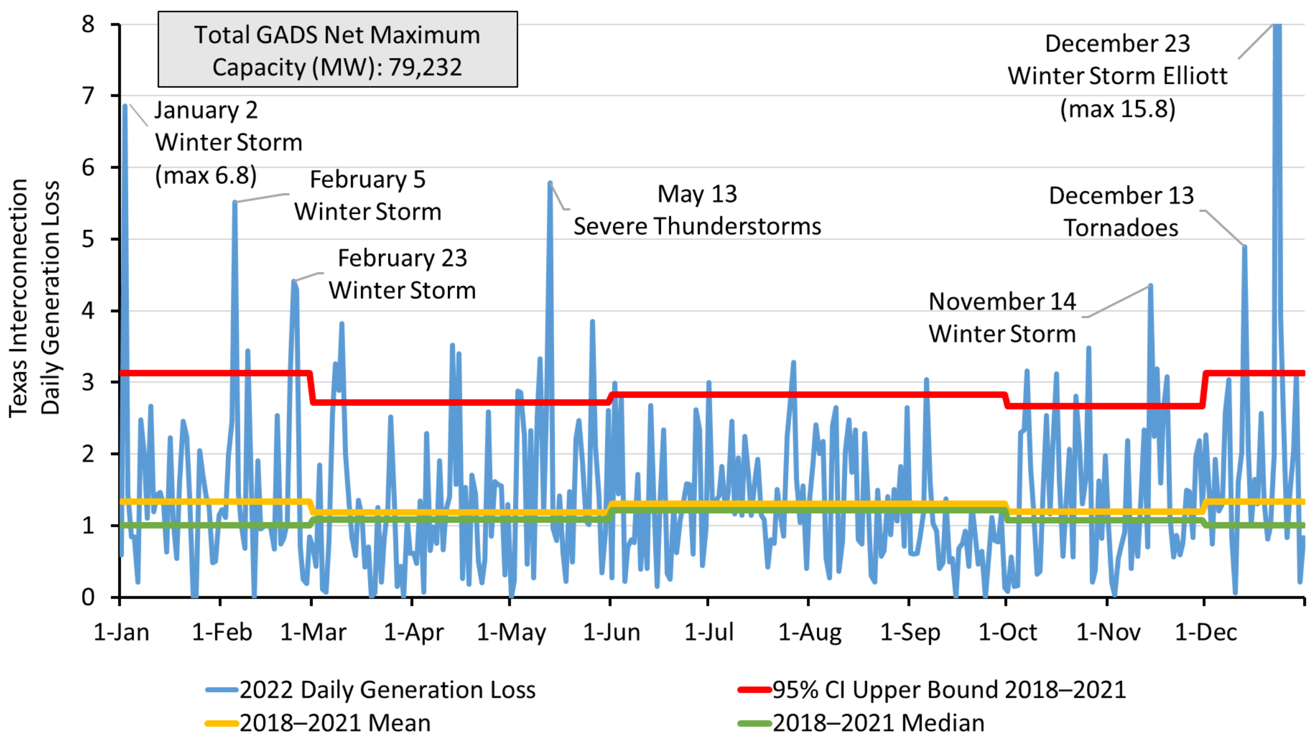

Figure A.8: Texas Interconnection—Generation Impacts during Extreme Days of 2022

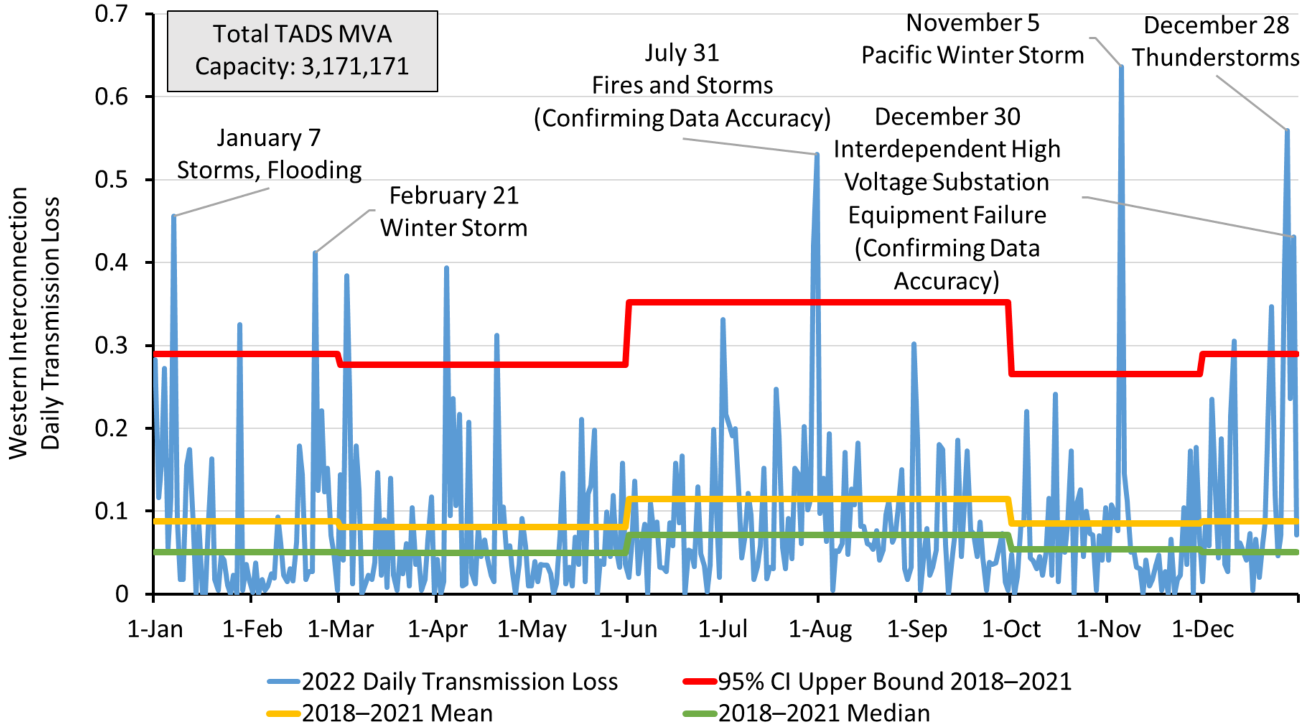

Figure A.9: Western Interconnection—Transmission Impacts during Extreme Days of 2022

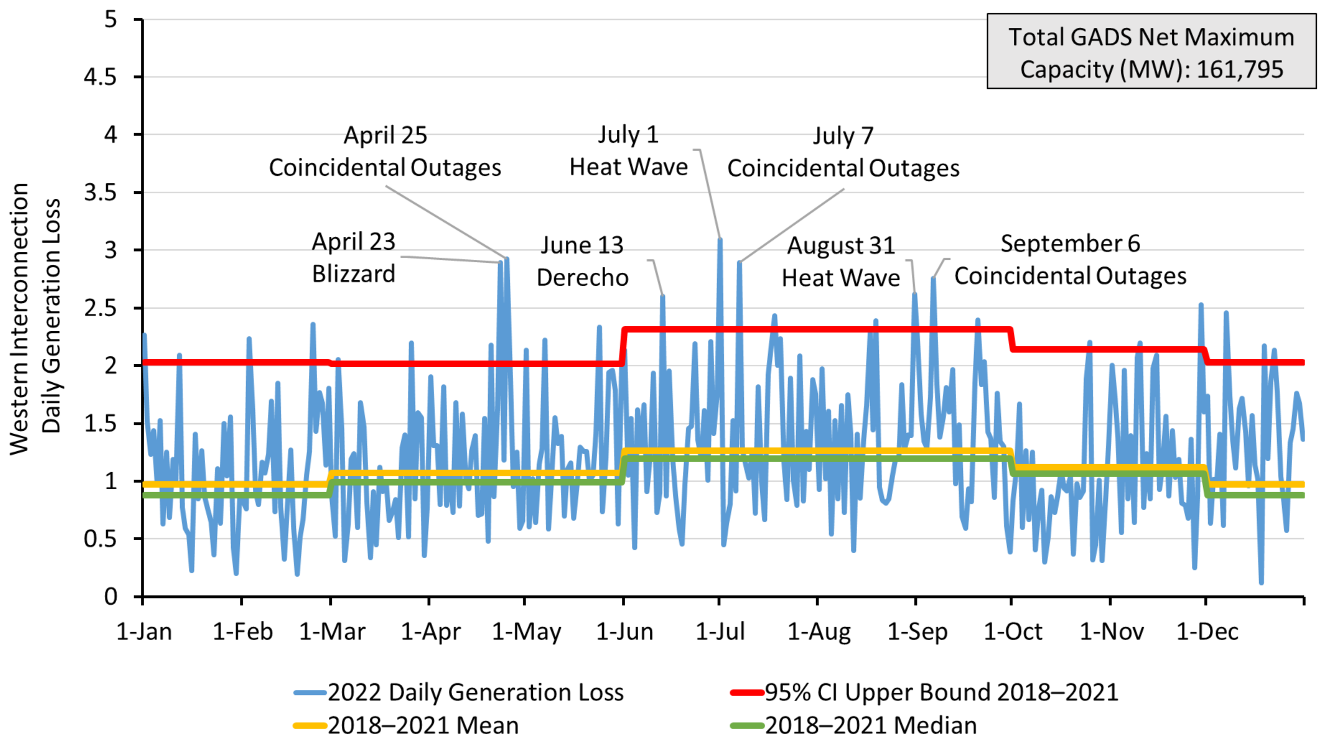

Figure A.10: Western Interconnection—Generation Impacts during Extreme Days of 2022

Appendix B: Acknowledgements

NERC would like to express its appreciation to the many people who provided technical support and identified areas for improvement as well as all the people across the industry who work tirelessly to keep the lights on each and every day.

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